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EPA PROGRAM CONFERENCE REPORT:
COAL CLEANING— AN OPTION FOR INCREASED COAL UTILIZATION?

Interagency Energy-Environment Research and Development Program Report

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16. ABSTRACT

This publication is the proceedings from the May 24-25, 1977, coal cleaning conference held in Arlington, Virginia. The Conference was co-sponsored by the U.S. Environmental Protection Agency and Battelle's Columbus Laboratories. The conference focused on the present status and future possibilities of coal cleaning technology, with emphasis on regulatory, institutional, and economic factors. Papers describe application of alternatives vs. coal cleaning. Examined are regional constraints such as water requirements, infrastructure, transportation support and institutional changes.

Included are discussions by experts from Federal energy and environmental organizations, utilities, financial institutions, industry and research organizations. Discussion cover the total coal cycle - from regional coal resources to coal delivery systems and various ways of using coal i.e., the potential of coal cleaning and the problems - including financing - of transferring coal technology to commercial practice.

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EPA PROGRAM CONFERENCE REPORT:

COAL CLEANING — AN OPTION FOR INCREASED COAL UTILIZATION?

A Conference
Presented at
The Sheraton National Motor Hotel
Arlington, Virginia
May 24 and 25, 1977

Co-Sponsored by
U.S. Environmental Protection Agency
Battelle's Columbus Laboratories

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FOREWORD

This report is composed of papers presented at a two-day conference on "Coal Cleaning: An Option for Increased Coal Utilization?" held in Arlington, Virginia on May 24 and 25, 1977. This conference was cosponsored by the U.S. Environmental Protection Agency and Battelle's Columbus Laboratories.

Because environmental standards affect the development of a technology for utilizing much of the nation's coal, the most desirable means for minimizing pollution from coal is being sought. Pollutants can be controlled: prior to combustion by systems for cleaning (processing) coal of undesirable constituents; during combustion, as for example, by using fluidized-bed combustion techniques; after combustion by processing effluents and emissions, as for example, flue gas cleaning; or by combinations of these various methods depending on the properties of various coals in conjunction with their energy generating systems.

The purpose of the conference was to discuss the present status and the future potential of coal cleaning technology, with emphasis on regulatory, institutional, and economic factors. Papers were presented describing (1) application of alternatives, particularly flue gas desulfurization versus coal cleaning; (2) alternative configurations of coal cleaning in combination with other desulfurization options; (3) centralized versus decentralized systems; (4) standards considerations for new and existing plants; (5) regional constraints such as water requirements, infrastructure, transportation support, and institutional changes; and (6) the potential of coal cleaning and the problems—including financing—of transferring coal technology to commercial practice.

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Stephen J. Gage
Environmental Protection Agency

Edward W. Ungar
Battelle's Columbus Laboratories

OPENING REMARKS

Stephen Gage
U.S. Environmental Protection Agency

Good morning. I am Stephen Gage your EPA cochairman for the conference. It is a pleasure to welcome you to this conference which bears on a subject that may be paramount to this country successfully increasing its utilization of coal. We are pleased to have Battelle's Columbus Laboratories cosponsor this conference on coal cleaning. Ed Ungar from Battelle is cochairman of the conference and will preside over tomorrow's meetings.

For our luncheon speaker tomorrow, the conference is honored to have the Senate's foremost authority on coal, the senior Senator from West Virginia, the Honorable Jennings Randolph.

Last October, we sponsored two sessions at the American Institute of Chemical Engineer's Fourth National Conference on Energy and the Environment, which was held in Cincinnati. These sessions highlighted our interagency coal cleaning program and emphasized technological issues.

During the next 2 days, we will focus our attention on the barriers, other than the technological ones, that have prevented a maturing of a technology oriented towards sulfur removal. We will present the status and possibilities of coal cleaning with emphasis on regulatory, institutional, and economic factors. And from the discussion periods and tomorrow afternoon's panels, we hope to leave here tomorrow with not only a better understanding of the obstacles that we face in advancing this sulfur control technology option but also with a realization of how each of us can exert an influence to foster coal preparation for pollution control.

One of the primary goals of President Carter's Energy Plan is to increase coal production and use by two thirds—from the 660 million tons mined in 1976 to an annual production of more than 1 billion tons by 1985. Expansion of U.S. coal production and use is essential if the nation is to maintain economic growth, reduce oil imports, and have adequate supplies of natural gas for residential use. Although coal totals 90 percent of presently usable domestic fossil energy reserves, it currently is supplying only 18 percent of our nation's energy consumption. Seventy-five percent of our energy needs are being met today by oil and natural gas despite the fact that they account for less than 8 percent of our reserves. Since our resources of oil and gas are rapidly being depleted, this imbalance between reserves and consumption must be corrected by shifting industrial and utility consumption from oil and gas to coal and other abundant or renewable energy sources.

If there is one key to this country's energy future, as that future is reflected in the National Energy Plan, then that key is made of coal. In the words of the Plan, "Coal will meet the greatest portion of increased U.S. energy needs. A comprehensive coal research and development program is high priority. The program should focus on meeting environmental requirements more effectively and economically, and should seek to expand the substitution of coal for natural gas and petroleum products."

"In the short term," the Plan continues, "most coal will continue to be burned directly. Hence, the highest immediate priority" (I repeat, the President's Energy Plan states) "the *highest immediate priority* is the development of more effective, economical methods to meet air pollution control standards."

And the Plan goes on to cite coal cleaning as one of the technologies with great potential for meeting those standards.

Hence, there is no longer any question of whether, or how far, we will compromise our environmental goals to achieve expanded energy resources. There will be no compromise. The artificial dichotomy of energy versus the environment is disposed of like a red herring ought to be—in the trash. We *will* have the energy we need, and it will not be at the cost of our property, our health, or our sense of aesthetics. This is our National Energy Plan.

Since late in 1974, the EPA's Interagency Energy/Environment R&D Program has been building the foundation upon which such a national energy plan could be erected. Using the leverage which a $100 million per year budget gave us, we began developing the control technologies necessary to meet our dual goals of increased coal use and environmental protection. Seventeen different agencies and departments share in this program. Working with and funding the Tennessee Valley Authority, for example, we developed and proved on a commercial scale several flue-gas desulfurization systems. Working with and funding the Bureau of Mines, we supported pioneering work in assessing the cleanability of more than 400 different domestic coals. And working with several other agencies, including NIOSH, the Agriculture Department, and NASA, we began building the health and environmental information base necessary to make intelligent energy/environment decisions and to assure adequate reclamation of mined areas.

One of the ten principles of the President's Energy Plan is "that national policies for the protection of the environment must be maintained." As the President has stated in his Energy Plan, "It would be ironic if, in moving toward energy self sufficiency, the nation unnecessarily degraded the quality of the environment and made this country and the planet a less healthful place in which to live." To address the uncertainty which exists over the environmental impacts of an increasing number of coal-burning plants, a special committee will be appointed by the President. This committee will study the health effects of increased coal production and use and the environmental constraints on coal mining and the construction of new coal-burning facilities.

Another principle of the President's Energy Plan is the promise for "reasonable certainty as to Government policy." Consistent and certain environmental policy, however strong, should provide the confidence industry needs to make investments in energy facilities.

As I mentioned before, the President's Energy Plan also calls for an expansion of the Federal coal research and development program. Although coal preparation has long been used to remove ash, its application to sulfur reduction *per se* is not yet an established practice in the coal industry. Under this planned expansion of coal research, EPA, through its interagency program, will more intensely address the several technological problems that remain and will initiate efforts to help solve the institutional problems.

Included in our program are studies to understand the effect of the process variables on cost and on the efficiency of sulfur removal, and development of the necessary monitoring and process control capability to assure the consistent performance of coal preparation plants.

We will attempt to develop strategies for coal preparation use which will mitigate the institutional barriers. The central coal cleaning facility concept will have to be explored to satisfy small users who cannot afford the higher incremental costs of scrubbers to reduce sulfur emissions.

The program, as laid out by the President, will include research on coal cleaning systems as one option. Increased research will be devoted to developing means to control the fine particulate and sulfur oxide emissions associated with coal burning. In many situations, front-end coal cleaning by grinding and washing can reduce the free sulfur and ash content and thereby reduce the cost of meeting environmental standards.

Although the Plan also calls for expanded work in other advanced technology areas for meeting coal-burning emission standards, such as the fluidized-bed combustion process and coal conversion to gaseous and liquid fuels, we must realize that commercialization prior to 1985 is not probable. It is this near-term period between now and 1985 with which we will be concerned at this meeting.

In order to put coal cleaning technology in perspective, I believe it would be helpful to briefly discuss the Clean Air Amendments of 1970. These amendments provide the driving force for the control of sulfur oxide emissions from both industrial and utility boilers. They call for the achievement of ambient air quality goals for sulfur dioxide and other criteria pollutants through the emission control of certain existing sources called for in State Implementation Plans (SIPs). The Act also calls for the promulgation of New Source Performance Standards (NSPS) which mandate the installation of best commercially demonstrated control technology for the criteria pollutants, including sulfur dioxide, in each of the important polluting industries. EPA's presently drafted policy also calls for a compensating reduction of existing pollution sources when a new source is to be introduced into a nonattainment or polluted area. The net effect of all these elements of the Clean Air Act and its implementation is the requirement to control sulfur oxide emissions from all new utility boilers, some existing utility boilers, and some new and existing industrial boilers.

As I mentioned earlier, the President's energy program calls for a major commitment to increased coal burning, which can potentially aggravate some of our existing air quality problems. The essence of this policy is that there will be more new coal-fired utility and industrial boilers and major switching from present or existing oil and gas-fired boilers to coal-fired boilers. So what we can now envisage is a relatively stringent regulatory framework calling for the control of large and small combustion sources superimposed on a need to burn additional coal—much of it high-sulfur coal.

So where does coal cleaning fit in this complex situation? Well, coal cleaning has one major advantage going for it—it's the least expensive way of removing a given quantity of sulfur from coal. I am aware of no other technology, neither present generation, such as flue-gas desulfurization nor emerging processes, such as fluidized-bed combustion, that can remove a significant amount of sulfur as economically.

As we all know, physical coal cleaning used alone is limited in its applicability to certain cleanable coals. Despite this limitation, we think that the imaginative, forward-thinking utilization of coal cleaning can save the utility and industrial boiler operators, and eventually we consumers, a substantial amount of money. Coal cleaning alone, or in conjunction with partial or total flue-gas desulfurization can make a major environmental and cost savings impact over present control alternatives.

Let us talk about ways of using coal cleaning. We will hear more about these during the course of our conference, but I think it might be appropriate for me to at least touch upon some of the possibilities. The Homer City plant of the General Public Utility Corporation is a good example of an imaginative use of coal cleaning. This plant is designed to meet both NSPS and SIP requirements, utilizing a multistream coal cleaning facility. One important possible variation of the Homer City approach might be a multistream facility producing various qualities of cleaned coal for a host of industrial sources; presently there is no established technology option to control sulfur oxide emissions from small boilers, in the size range of 25 megwatts or less.

Another scheme for utilizing low-cost coal cleaning would be to clean the coal as well as can be achieved for the given coal and then to burn the coal and subject a portion of the resulting flue gases to flue-gas desulfurization. The portion of flue gas not scrubbed can be used to reheat the cooled scrubbed gases by blending the two gas streams together downstream from the scrubber. This combination of current technologies can lead to substantial cost savings for many applications. These are just a few of the ways we think that coal cleaning can be effectively utilized.

In my opinion, coal cleaning is an under-utilized technology. Considering the importance of sulfur oxide control from a variety of combustion sources and considering the high cost, in many cases, and large scale of flue-gas desulfurization, and further, the long distance transport of low-sulfur coal, it is strange indeed that there is so little activity in the coal cleaning area. I think that it is noteworthy that the Office of Management and Budget has asked the Environmental Protection Agency to work with other knowledgeable Federal agencies and private organizations to identify some of the barriers to the utilization of coal cleaning and to propose steps the Federal government can take to encourage the use of this important technology.

The report summarizing our findings will be provided to you later this year. The papers and discussions which we will hear at this conference will help assure the accuracy and relevance of this study. In conclusion, this conference should shed some light on the potential and the limitations of coal cleaning technology as a viable pollution control technology option, and should suggest imaginative approaches to the utilization of coal cleaning. We will focus on technical, institutional, and other barriers preventing timely utilization of this technology and, I trust, identify some approaches for overcoming these difficult barriers.

Coal cleaning is an exciting technology. It is exciting not because it is new, but because it is old, not because it is so complex, but because it is straightforward, and not because it poses an insurmountable challenge, but because it offers uncounted solutions to perhaps the greatest challenge of our time. That challenge is an all-out effort to shift our entire culture away from the mode of wasteful, destructive exploitation of our resources and toward the mode of creative harmony with regard to our natural resources.

Thank you. I hope you enjoy our conference and I look forward to meeting with you on a more personal level during the reception this evening.

LUNCHEON ADDRESS

COAL CLEANING—A VEHICLE FOR MORE EFFECTIVE COAL UTILIZATION

The Honorable Jennings Randolph
U.S. Senate

The energy problems we face stem from a long history of unintentional neglect and the manner in which we have attempted to shape the components of the United States energy policy. No single villain has brought us to our present situation, just as no simple and single action will suffice. It is essential that conferences such as this one—on coal cleaning—continue to provide the opportunity to counsel together. We must try to mold pieces of the puzzle which will ultimately provide our total energy approach.

A recent report stated that the annual United States consumption of wood, coal, crude oil, natural gas, hydroenergy, and nuclear energy from 1850 to 1971 totaled 158 quadrillion Btu's. A tremendous amount of fuel was used to create this energy output.

This serves to highlight that individually we enjoy a short span of responsibility and involvement with energy problems. We tend to ignore how similar, in certain areas, the past patterns of energy growth or replacement have been to those of today. Because our figures are dramatically large now, does not mean that all changes of recent significance have occurred in the last few years.

A fact is that our use of energy has been moving constantly upward since before the turn of the century. So the energy gap which exists today has not been a product of the last two or three decades, but one of a much longer period. We must now as a Nation reach toward a consensus on exactly what is the energy problem. The problem has several parts, each of which influences and is influenced by other national goals such as a clean environment, full employment, and national security. I believe the diversity of our natural resources—with coal as a base—with the capacity and desire we possess for using energy more efficiently will give us room to maneuver and finally solve these problems.

The pattern of coal consumption has changed significantly since 1945. At the end of World War II, coal had major markets in the railroads, manufacturing industries, home heating, and in coking plants for steel. Since then, however, America has left the coal bucket behind, and is not likely to bring coal back as originally used. Homes, businesses, factories, and transport systems today require energy in three basic forms: electricity, pipeline gas, and a variety of petroleum products. Thus, coal must be converted to these forms. Why? Because our coal reserves are sufficient to last for several hundred years and can supply power, gas, and oil in large commercial volumes.

Coal is the one fossil fuel that is likely to remain in abundant supply at relatively low cost for the remainder of this century and into the next. It is the one major alternative replacement fuel that can bridge the gap from our current dependence on oil and gas to a future era of renewable energy resources.

In 1976, United States coal production reached 665 million tons, up 10 percent from the 1974 level but only 3 percent over 1975. Those most closely involved with energy problems in our country would like to see coal production increased to at least 1.2 billion tons per year.

Coal is an effective source of heat and can be converted into gaseous and liquid fuels and chemicals. The role for coal as a natural successor to oil and gas is thus established. Realizing coal's potential will, however, depend on a recognition of the need to use coal, and the necessary policies to make such use possible.

The Energy Supply and Environmental Coordination Act of 1974 has required the Federal Energy Administration, under certain circumstances, to issue orders to power plants and some major industrial installations to convert or start using coal, rather than oil or gas boilers. On May 11, 1977, the Federal Energy Administration announced its first round of orders to major industrial plants under the provisions of the 1974 Act.

The "notices of intent" will require industries to convert to coal utilization in plant activities. A total of 56 "notices of intent" were issued in 25 states. Of these, 24 were to plants currently burning oil and gas as fuel. The other 32 are construction orders to plants in the planning stage, which will from "day one" burn coal.

The first round of "notices" to utilities were announced in June of 1975. A second round was issued in April of this year. If all 102 boiler operations at the 50 sites told to convert to coal by the Federal Energy Administration comply, the yearly energy savings would be 84 million barrels of oil and 59 billion cubic feet of natural gas.

The question still remains as to whether to continue intervention by the Federal government as a necessity to increase the use of coal in utilities and industry. To encourage greater coal utilization, I introduced S.273, the Natural Gas and Petroleum Conservation and Coal Utilization Act of 1977 on January 14. This bill would prohibit construction of new electric power plants and major fuel-burning installations not using energy sources other than gas or oil. In addition, it would extend the Federal Administration's authority to issue construction and prohibition orders until September 30, 1980. Installations constructed to use alternative energy sources, of course, must be consistent with environmental policies. This measure would provide a stability to future energy supplies not presently afforded by oil imports.

Last week, the Senate passed S.1469, a measure that would extend the Federal coal conversion program for 6 months under Section 2 of the Energy Supply and Environmental Coordination Act of 1974. This would allow for the Federal Energy Administration to consider a second round of construction and prohibition orders until January, 1978. It would also give the Energy and Natural Resources Committee extra time for full consideration of proposals for broader coal conversion authorities. Evaluation of these proposals can now proceed without disruption of the present coal conversion program.

Participants in this conference know that a major proposal before the Energy and Natural Resources Committee is the Coal Utilization Act of 1977, which incorporates provisions from my bill, S.273, and reflects the findings of the Senate's National Fuels and Energy Policy Study started 6 years ago. Today, the Committee met in its final day of hearings on this bill, and mark up will begin in early June.

Realizing coal's potential also will require satisfactory solutions to the environmental problems associated with its mining and burning. Congress has determined that where the physical and economic capabilities to burn coal exist, coal should be burned—but only to the extent that environmental constraints permit. As Chairman of the Committee on Environment and Public Works, I am concerned that we maintain the momentum of recent years in achieving a cleaner and healthier environment. Energy production and environmental improvement need not be conflicting goals. We can have a wholesome society at the same time we have a productive society. But we must agree that the issues surrounding growth and environmental quality are reconcilable. That has yet to occur. I am encouraged by conferences such as this in which I see advocates of both environmental protection, and growth and production working together to find better ways to clean our coal.

On May 10, 1977, we reported the Clean Air Amendments of 1977 (S.252). The underlying premise of this legislation was the continuing preservation of the fundamental belief that public health should not be compromised in the pursuit of economic growth. Federal minimum source performance and ambient air quality standards are essential.

The bill does not contain modifications that will facilitate our national conversion effort to coal. Under its provision, the states that originally established more stringent emission standards than necessary to meet national ambient air quality requirements can revise them to assure they are reasonable and equitable.

Citizens of a state or regional area will be afforded an opportunity to influence the character of economic growth in their region by making their own decisions on certain aspects of new sources. This will enable some industries to burn a lower grade of coal and allow increased sulfate emissions in some areas. When national ambient air quality standards for protection of public health are being achieved and maintained; and when Federal new source performance standards will be met; then the States, in my judgment, should have sufficient flexibility to determine what are the appropriate environmental requirements to achieve economic growth with environmental quality.

Such decisions should be reached with public participation. The burden of proof should be placed on those individuals proposing new construction to justify its associated environmental impacts.

Another provision of the 1977 amendments, which I introduced during Committee consideration, recommends that one state may no longer allow emission of pollutants that adversely affect a neighboring state. A facility located in one state must notify the adjoining state of the potential impact of its emission prior to the commencement of construction of a new facility or modification of an existing stationary source. The amendment also provides that a state or local subdivision may petition the Administrator of the Environmental Protection Agency for relief if a facility would be in violation of the adjoining state's air pollution standards.

It is essential that the Clean Air Act provide a mechanism for equality of enforcement of applicable air pollution laws among the various states. The Clean Air Amendments of 1977 are scheduled to be debated in the Senate next week.

I emphasize that we need to remain vigilant in our quest to achieve acceptable methods of removing most of the sulfur from the coal we burn. Almost one-half of the electric energy in America is generated today by coal-fired plants. But one of the biggest problems the coal industry faces is that the bulk of recoverable reserves, as well as much of present capacity, does not meet today's sulfur standards. Forty-one percent or 176 million tons of the coal burned by electric utilities in 1975 did not meet sulfur standards. In the East, 48 percent of the coal burned could not comply. So the question is: "How can we best clean coal to make electricity?"

Scrubbers will be improved and used. By the year 2000, most of the electricity made from coal will still be made, as it is now, by burning it in pulverized fuel boilers—large numbers of these boilers will probably be fitted with scrubbers. There are some 6,000 megawatts of scrubbing capacity now in existence, and some 40,000 more are in design or construction. Scrubbing adds about 20 percent to new power plant investment. Moving Western low-sulfur coal to the East, to avoid scrubbing, requires the same 5–8 percent energy loss for transportation as does the scrubbing process itself. The cross-country transportation of Western coal to avoid scrubbers, therefore, is not economical.

In the long term, significant improvements also are possible in the direct utilization of coal by fluidized-bed combustion. This technology offers dramatic improvements in the efficiency of coal utilization and in reducing adverse environmental impact when compared with conventional systems. A fluidized-bed test facility is planned at the Morgantown, West Virginia Energy Center by the Federal Energy Research and Development Administration.

Development of coal-related technologies will be accelerated. As we develop these technologies (especially scrubbing techniques), I hope to see the Environmental Protection Agency, and the new Energy Department, do more extensive research into the extent that sulfur oxide and other sulfur compounds cause major health hazards.

When and if a final consensus is reached on coal conversion, the policy on which it is based should state that:

- High-sulfur coals must be used in producing a large part of our power.
- Scrubbers constitute the best immediate answer to pollution control until technologies such as fluidized bed are commercially developed.
- Where air quality standards are not impaired, coal washing and regional coal blending can meet the requirements of sound public policy, and scrubbing devices can be delayed or further improved.

A National Commission on Energy Policy might be the forum on which to build such a consensus. A Commission could make a complete investigation of the 71 separate measures that have been enacted into law over the last 5 years. I introduced legislation creating such a body on March 15 of this year.

Total recoverable reserves of low-sulfur coal in the United States are estimated at about 67 billion tons. Of this amount, only about 14 billion tons are in the East, and much of this is high quality metallurgical coal already owned by or dedicated to the steel industry. These facts, however, should not keep us from mining what is available. The Appalachian region contains abundant coal resources that can only be competitively mined by small producers. Eighty percent of the low-sulfur coal reserves east of the Mississippi are in states where small producers predominate.

Small coal producers in Appalachia often are unable to obtain necessary financing to expand production. The Federal loan guarantee program enacted by the Congress in December, 1975, has never been utilized by the Federal Energy Administration despite the congressional mandate and the urgent need for financing by hundreds of coal producers in the region.

To encourage the production of environmentally acceptable coal supplies, the 1975 Act authorized loan guarantees to small producers for expansion of new underground low-sulfur coal production. This program was reaffirmed by the Congress in August, 1976, but the Federal Energy Administration has not implemented the program. The Bureau of Mines estimates that over 5.2 billion tons of Eastern low-sulfur coal reserves would be potentially eligible for Federal loan guarantees if the program is implemented. Under the loan guarantee program, an estimated 20 to 40 million tons of coal could be produced annually by 1982. By comparison, only 14 million tons of Eastern low-sulfur coal were delivered to utilities in 1975.

The entire United States economy is at present three-fourths dependent on diminishing domestic supplies of petroleum and its geological partner, natural gas. President Carter is making a praiseworthy effort to persuade American citizens to come to grips with the genuine energy crisis facing our nation. I have commended the President for his recent energy proposal to Congress. The previous five consecutive administrations have failed to come to grips with this problem.

His proposals to increase coal production and utilization need some modification. When we get into specific details on legislation it is quite likely that this can be worked out.

His proposal to Congress does not include a comprehensive plan for synthetic fuel development. Coal conversion can rapidly increase coal utilization for heating the power. At the same time, we must advance the production of synthetic fuels to supplant oil and natural gas.

The coal industry faces tremendous problems in increasing its annual output by two-thirds, to 1.2 billion tons by 1985. I had hoped that the Carter energy program would recognize these problems, the potential shortages of manpower and materials, and the tremendous capital investments that will be required. Above all, there must not be unnecessary restrictions which would impede the production of coal.

His proposal to significantly increase gasoline taxes presents problems. It will require that American people change their travel habits. I believe that consumers are ready to make sacrifices, if they are convinced that such sacrifices are equitable and fair. But they are not ready to assume hardships that will not produce results.

In West Virginia for example, many coal and industrial workers must drive as much as 80 miles a day to get to and from their jobs. There is no public transportation in most of these rural areas. Something will have to be worked out in cases such as this, when long auto travel is necessary. Hearings are scheduled to begin in June on the nontax provisions of the President's energy proposal in the Energy and Natural Resources Committee.

Choices that we make today will seriously affect our options for the future. The decisions we make in the next few years will have far-reaching consequences. International policy is closely linked to how we handle our energy problems and we must develop them together. Environmental policy is, as I have emphasized, intertwined with energy production. Federal energy resource management also has an essential bearing on energy issues. It affects adequacy of domestic energy supplies, energy prices, and environmental protection because most of the nation's undeveloped energy resources are on government land.

Coal conversion is one energy choice we have before us. There is more than one path before us involving the development of energy—nuclear, solar, hydro, win ss thetic fuels—each has its own advantages and pitfalls. Our primary task, as members of the concerned energy community and energy-conscious citizens, is to inform ourselves of what lies ahead before we choose our way.

THE IMPORTANCE OF COAL IN MEETING NATIONAL ENERGY NEEDS

Harrison Loesch
Peabody Coal Company

The abstract of this talk, which appears in the program, speaks to the present and future and says nothing of the past. However, using a speaker's privilege, I want to review a few of the interesting and instructive facts which form the story of the coal industry.

It startled me to discover, for example, that it took more than 20 years to exceed the production level of 1919. It is, perhaps, equally surprising that the average per-ton value of coal in 1920, which was itself more than three times that of 1915, was not reached again until 1947. But if you think that's bad, how does it strike you, considering the general increases in cost in the following decades, that the 1948 price was exactly the same as the 1969 price? Indeed, at $4.99 a ton in 1969, coal represented perhaps the greatest energy value the industrial world has seen—but you couldn't sell much of it.

During World War I, the price of coal jumped from just over a dollar a ton to $3.75. By contrast, the Second World War resulted in only the small increase from over $2.00 to about $3.00. It wasn't a war, but the Arab Embargo of 1973, together with the serious inflation we were then experiencing, that doubled the price from $7.66 average in 1972 to $15.75 in 1974.

In 1920, we produced over 560 million tons of coal from 9,000 mines, all by hand, and all but 1 percent or so from underground. It took almost 650,000 miners to do this, producing as they did about 4 net tons per man, per day, and working an average of 220 days. Kicking and clawing and trying to survive through the '50's and '60's, with total annual production decreases almost year by year—losing its best customers and finding its new customers most difficult to handle—the industry survived by maintaining its price level and increasing its productivity. By 1969, we were about back to where we were in 1920 in tonnage, very little above in value, producing from only 5,000 mines. With 125,000 miners employed, we were, by the aid of immense and costly machinery, digging 20 tons of coal per day per man, half of it from surface mines.

During the interim, the industry had barely managed to keep its head above water by changing from a labor-intensive to a capital-intensive process. And by meeting the demands of price, it sowed the seeds of obloquy and criticism. During much of this time, government policy was *all* price, and its own agencies, like TVA, demanded the lowest possible penny per ton—and the hell with the land, the air, or the water.

Now we are hearing that coal is our savior—that in the near and mid-term—not so very near and not so very mid—we must look to it for our energy salvation, pending the widespread use of new and esoteric forms. After all the lean years, this should be flattering, but the industry sees breakers and hidden rocks ahead. In fact, its leaders may be pardoned, amidst the publicity campaign in behalf of their product, if they say like Mark Twain's man who was tarred and feathered and ridden out of town on a rail that "If it wasn't for the honor I would rather walk." Because, you see, these coming dangers are new and different and scary ones, requiring substantial change in one of the nation's most conservative—not to say old-fashioned—industries.

Where do we go from here? What does our society now demand of the industry? Will we meet that challenge and what will it take to do it?

The government says it wants us to produce in excess of a billion tons of coal annually by 1985. The industry's projections indicate that it will do so. Perhaps without any margin at all. But what is produced is a function of what can be sold, as well as the function of lead times, investment, transportation, and labor force. Although these factors are all mixed together, along with others which more directly concern our customers, let us try to examine them in order.

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Lead Times. Not very long ago, the coal industry could, from a standing start, open a new underground mine in about 2 years from the day it decided to do so. Similarly, if you had an available dragline or shovel, a surface mine would be opened in a matter of months. And even if you didn't have such a piece of equipment, one could be bought and built within 2 or 3 years. Such times are gone forever.

Today, the permitting process is such for both underground and surface facilities that planning must be in terms of decades, not years. You think I am exaggerating. Perhaps I am just a bit, but a new study by a Federal inter-agency task force has produced a flow chart which shows a 10-year gestation period for a surface mine on Federal coal land in the west. Based on Peabody's experience, this 10-year time frame is very optimistic, allowing nothing for litigation, moratoria, or other unplanned lapses. The volume and complexity of the required environmental information necessary even to apply for a mining permit is such that it takes years to obtain and more years to evaluate.

For private land and private coal, the period may be somewhat shorter, though we have yet to experience the exigencies of the forthcoming Federal Surface Mining Act. That Act will apply the same strict standards we are now dealing with in Federal lands in the west to all the lands and all the coal in the United States, and in spite of its ills, it applies not only to surface mining, but to "the surface effects of underground mines", and thus subjects all coal mines to essentially the same permitting and regulatory process.

But although we may be well along in this permitting process, when should we order and how should we finance the necessary dragline? Instead of the $5 million it cost in 1969, the same machine will cost between $15 and $20 million today, and instead of 2 or 3 years of construction time, it will take 5. How do you know until you actually have it in your hand that you will get the permit which will allow you the use of the machine, the final construction of which must be done on the spot where it is to be used? When do you, as the chief executive officer of the company, dare to take the chance of ordering and committing to pay for such a machine? It ain't an easy decision to make, friends. If you wait to be safe, you postpone mining; if you take a chance, you could well go broke.

Investment. The coal industry has always been and is now a poor one, without the massive cash flows of oil, steel, automobiles, or others you could name. In today's inflated prices, it is valued at $5 billion. It is estimated that it will cost $15 billion to increase its production to the level desired by 1985. In the past, the industry has always raised a very large proportion of its money by obtaining firm, long-term contracts for a certain amount of coal, and using the contract as security for the financing of the mine. This method of financing demands the faith of the lender in the long-term stability of the industry, as well as the faith that the customer, usually a utility, will be able to pay for the coal as he receives it over the term. Today, considering the money and lead times involved, the uncertainty of the customer as to what coal he will be allowed to use, under what conditions and for how long, it is improbable in the extreme that we can obtain the funds to do the job in the way we have been used to.

Transportation. Suffice it to say for the moment that today the roadbeds of our railroads are sadly deficient and their rolling stock so sparse that they are hardput to handle present volumes, let alone a doubled service. Similarly, our barge traffic has reached an all time high, taxing the capacity of the locks on our major inland waterways, which have been allowed to deteriorate unconscionably in the last 30 years. Coal slurry pipelines are not in the picture today, and if painted in will have lead times of their own which will make substantial transportation by this means impossible by 1985.

Labor Force. I want to discuss this factor at a bit more length later on, so I will only say here that under current conditions, the lack of a sufficient trained and dedicated force of miners, both surface and underground, is a major constraint to substantially increased production in the near term.

While I am being a Cassandra, let me add a few further gloomy thoughts. At this point in time, our customers appear to be unconvinced that they can use the large increases in coal production projected by the industry and the government. Also, it is questionable in my mind, given our statisticians disinclination to borrow trouble, whether in making predictions they took into account further administrative restrictions. Today, 55 percent of our coal is surface mined. Today, Congress is in the final stages of passing the act which, while intended to require the full reclamation of mined land, in fact removes the possibility of using some large reserves, and without promoting reclamation causes far greater difficulties in the mining of other reserves. Although I would be the last to say that the coal industry has not abused the land in the past, I agree with those who believe that the local concern and the requirements of the state laws in the producing states have already met the problem and solved it for the future. But the federal act is all but a *fait accompli*, and perforce the industry will live with it and cope with the new bureaucracy, the extensions of the lead times, the increased expense, and the other ills it brings in its train. Of course, your light bill will go up!

And, at the same time your light bill will go up farther for another reason. Utilities, like the coal industry itself, are struggling with the problems of the strict requirements of the Clean Air Act. Far from showing a desire to moderate its requirements, The Congress and The Administration appear to wish to strengthen them. Until a final decision is reached, the utility industry and its lenders are left in uncertainty and doubt as to how much and what kind of investment is required to meet the need. All we can say now is that that investment will have to be nearly astronomical in new plants and environmental equipment, and where it is to come from has not yet been determined.

Right now, at the sacrifice of huge transportation costs and consequent expenditures of energy, some utilities can comply with the Clean Air Act by burning Western low-sulfur coal. Because it is only two-thirds the Btu content of Eastern and Midwestern coal, it takes that many more tons to produce the same number of kilowatts, and is a temporary solution at best if our society is to stick with the current clean air requirements. Although the utility industry opposes it, it is my impression that the best and fairest solution to bring stability to that industry, protect the environment, and hurt nothing but the consumer's pocketbook, is to require scrubbers on all utility plants built in the last 10 years and to be built in the future. While expensive, this solution would reduce the market advantage of Western coal, stabilize the Eastern and Midwest industry, and prevent the degradation of the pure Western air even if a large number of megawatts were to be produced in mine-mouth plants. As has been found at the enormous Four Corners plant in New Mexico, retrofitting is both expensive and initially inefficient, but, under force-feeding, that technology, too, is fast improving. It is possible, of course, that alternative processes can be justified for new plants and, no doubt, you will hear more of these possibilities in the technical discussions in this conference.

As a layman, it would seem to me that combustion cleaning, as in the fluidized bed, is theoretically preferable to after-the-fact cleaning, as in stack scrubbers, but the engineers will have to tell you about that.

Having thought of all—or at least most—of the bad things standing in the way of the large expansion of our industry and of the use of our product, can be balance the scales? Yes, indeed, we can, and as a matter of fact we *will*, simply because if we do *not* our prospects as a nation are too bad to be borne.

I have not heard it argued by any knowledgeable person that we have a real alternative to an expanded use of coal as a major energy source until at least the year 1990, and most probably the turn of the next century. With coal representing 80 percent of our total energy reserves, and only 18 percent of its use; with public and administrative disinclination to rely on nuclear energy, and particularly upon the development of man's best true perpetual motion machine—the fast breeder reactor; with the tremendous amount of R&D and dedication of land and other natural resources necessary to the production of solar energy in any significant amount; and with all other sources together, such as geothermal, hydro, refuse burning and the like, capable of minimal contributions to the total mix; with all of these considerations, I say we have no alternative to coal. So undoubtedly, in our Yankee tradition, after the usual pulling and hauling and arguments, we will use it in the proper amounts and at somewhere near the proper time.

Certainly, if we have a national will to use coal where we can, to preserve our other fossil fuels for high-priority uses, and to conserve energy to the extent that such conservation does not cause stagnation, we can do the job. Certainly—at least by lip service—we have already seen a moderation in some respects of the attitude that our ugly duckling product is a no-no. It was long in the position of the child in the story of the drunk who sat down by the lady in the parlor car . . . not too long ago, it was being said that coal may be our salvation, but we are not allowed to mine it, transport it, or burn it!!! In spite of the exercise the government is now engaged in of giving with one hand and taking away with the other, coal production will rise. The economic costs we are now charging ourselves with, by way of hauling millions of tons of low-sulfur coal from the Great Plains to the Midwest, at a substantial cost of energy for haulage and a tripling of the price of the product, will cease eventually. By the nature of things, Appalachian coal will serve the Appalachian and Northeast areas. Border and Midwest coal will serve the Southern and Midwest areas. Great Plains and Rocky Mountain coal will serve their areas, shipping the excess in one form or another to the concentrated populations of the West Coast and the Southwest.

But even so and notwithstanding, there will be a tremendous amount of coal moving about the country. What are the constraints? First of all, our railroads, in order to handle the prospective volumes in reasonable fashion, must have a massive infusion of capital to upgrade their roadbeds and furnish the necessary equipment. That equipment, whether owned by the railroads or the customer, must entail many thousands of new coal cars. They will come from somewhere.

Second, the locks of our interior waterway system are presently bursting at the seams from the excess of barge traffic hauling coal up and down the major waterways. The stalemate in the repair and reconstruction of these facilities must be broken and progress made in the construction of new links, such as the Tennessee-Tombigee project. This will be done.

Lastly, we must provide for the installation of potentially highly efficient slurry line systems. As you know, unlike pipelines for oil and gas, which have for many years enjoyed this franchise, coal slurry pipelines have no cachet of eminent domain and cannot condemn the required right-of-way. It is not hard to detour around a farm, but how are you going to detour around a railroad? And the railroads, despite their own inability, both now and in the future, to handle such transportation are taking a dog-in-the-manger attitude and opposing such authority. In a secondhand sort of way, my company has had substantial experience with slurry lines, being on the producing end for the 275-mile pipeline from the Navajo reservation to the Mohave plant in southern Nevada.

This is a cheap, efficient and highly satisfactory transport system. We should try it in other areas over longer distances and under greater volumes. Of course the railroads are not the only opponents of such a system. Among the Western States there is no more sensitive subject than that of water, and the arid states will protect their supplies of this scarce commodity to the death. It is, therefore, of little practical use to plan the exportation by slurry pipeline of any water at all, let alone substantial amounts from Montana, Wyoming, or other other High Plains states, unless there is also planned a system to replace that water. Perhaps an economic method by way of a loop-line could be developed for this particular situation. Elsewhere on routes where the water supply is not so crucial, this problem may be minor. At any rate we'll solve this puzzle or substitute another answer.

And now to discuss the last serious roadblock in the path of greatly increased coal production and efficient use of the product: the labor force. Earlier, I told you that the industry used 650,000 miners in the early '20's as against 125,000 in 1969. That work force has now grown to nearly 200,000 people, but productivity has been going down, down, down, since 1969. This is a function of the very strict and comprehensive safety and health requirements of the law, of turmoil in the United Mine Workers of America, and of a younger, more educated, and more militant mix of miners. This loss of productivity and the prevalence, in spite of the national contract provisions, of unauthorized work stoppages—"wildcat strikes," if you will—is one of the most worrisome features of the coal world today. Somehow, some way, we must bring about industrial peace and at least a reasonable amount of mutual trust and confidence between the work force and management and, in addition, we must add substantial numbers to this highly skilled work force in the next few years. A miner today is no pick and shovel man, but, instead, a highly skilled technician who is paid in proportion, at the highest rate of industrial remuneration in our country today. A neophyte earns over $50 each day he works, and costs his employer another $20 or more in fringe benefits. But it is still a comparatively dirty and dangerous job, and except in the midst of Appalachia not looked upon as a preferred career.

Well, it is up to the industry and the union to encourage training and provide the men we will need in the next few years.

I have tried, this morning, to press home the point that turning to coal may be necessary, agreed upon, and the way to fly, but that it ain't easy. One of our classic environmentalists observed that everything is connected to everything else, and that is as true in industry, economics, and all aspects of man's modern society as it is in raw nature undisturbed by combusting anything.

Thank you!

ECONOMICS AND TECHNOLOGY OF COAL UTILIZATION*

Richard E. Balzhiser
and
Dwain F. Spencer
Electric Power Research Institute

If you're working with a coal-burning electric utility today, you could be looking into as many as two dozen ways to use coal as a fuel. They vary from the direct firing of low-sulfur coal to the burning of low- or medium-Btu gases derived from processes still in development.

In between those extremes is a spectrum of both generic and proprietary approaches:

- Intermittent generation controls to cut the volume of sulfur dioxide emissions when ground level concentrations get too high
- Filters and scrubbers to clean combustion products before they go up the stack
- Washing and chemical cleaning schemes to remove sulfur, as well as particulates, ahead of the combustion process
- New combustors and combustion processes that minimize the release of sulfur compounds
- Liquefaction processes (like those for gasification) that convert coal's heating value to an entirely different, clean, efficient form

But is there a best way to use coal? Which way? How do we decide? And what do we do about it?

TOO MANY VARIABLES

Measuring the state of the art in coal technologies is difficult. For one thing, differences between processes tend to make any comparison a matter of "apples and oranges"—because of the subtleties of chemistry that govern feedstock requirements efficiencies, and throughputs. Then there are the differences in the states of development of candidate processes that defy easy or precise prediction of time and cost to commercialization, land and other resource requirements, operability, reliability—and even the very probability of development success.

Equally important are the number and range of what economists call exogenous variables, those that originate outside the R&D community but bear significantly on the practical economic potential of any approach to coal cleaning or conversion. One such factor is the resource base itself—our reserves, their character (especially their sulfur content), and their geographic distribution. Another factor is the coal industry and its technologies and capabilities for growth in mining and transportation. Together, the two factors will influence the quality of coal and the price electric utilities will pay for it.

In addition, of course, there is the electric utility industry, with all its own variables in system load characteristics, growth, reliability, capital and operating costs, and fiscal capability of taking on new or modified generating plants. Regulation enters the analysis, too, not only in affecting revenue requirements but in setting environmental standards for coal-burning plants.

SELECTING A YARDSTICK

The list of variables goes on. However, a yardstick is necessary to guide R&D efforts on behalf of utilities. Designing and applying that yardstick, in a first-cut, screening exercise, has been the aim of a technical analysis conducted by EPRI's Fossil Fuel and Advanced Systems Division during the past 15 months. The methodology and conclusions of that work are summarized here.

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*This paper is a reprint from the November, 1976 *EPRI Journal.*

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What follows, then, focuses on the yardstick, its construction, its precision, and its application. The measurement unit is a busbar electric power cost, figured in 1975 dollars and expressed in mills/kWh. Distinctions are not made between and within individual coal technologies, other than to name them and to characterize them by their sulfur removal capabilities.

Initially, a list of two dozen alternatives was drawn up. However, in many instances—notably coal cleaning, dry alkali/bag filters, and several regenerative scrubbing processes—the available basic data were inadequate for valid analysis. So the pioneer evaluation was necessarily limited to 10 options (Figure 3.1). As the study is updated (at least annually), however, many of the others will be incorporated.

Because all the candidate technologies are seen as options for limiting SO_2, even low busbar power costs would be meaningless if the options could not reasonably be expected to meet environmental standards. EPRI's work, therefore, also had to include some assessment of future sulfur removal requirements, based on projected coal utilization, environmental standards, and coal quality.

The remaining stages of the study were devoted to estimating the capital costs for coal cleanup or conversion plants to meet the calculated sulfur removal requirement and then computing busbar power costs for each candidate technology as it might be employed in both baseload and intermediate generation modes.

SULFUR CRITERIA

National energy consumption is expected to rise from 70 quads (quadrillion Btu) in 1975 to 170 quads in 2000. (With greater efficiency and the resultant conservation, the latter figure would be 150 quads, a value frequently used in energy growth estimates by EPRI.) Considering only the coal used for electricity generation, the need will increase from 11 quads in 1975 to 30 quads in 2000. This growth implies an increase in coal consumption by electric utilities from 400 million tons in 1975, to 900 million tons in 1985, and to 1500 million tons in 2000.

Based on a 3 percent annual replacement rate for coal-fired power plants, a capacity equivalent to 300 million tons (of 1975's 400 million) will have to meet what are called new-source performance standards (NSPS) in the year 2000—that is, control of sulfur emissions to at least the present upper limit of 0.6 $lb/10^6$ Btu. Of course, the capacity growth represented by 1100 million tons will be similarly governed. Thus, by the turn of the century, more than 90 percent of the U.S. utility coal-fired plants will be subject to NSPS levels.

MORE STRINGENT CONTROLS

But what is the likely level, or stringency, of sulfur control? Of course, it is not certain what action various federal, state, and local agencies engaged in environmental regulation will take. But several present and probable strategies were considered in the study, with particular respect to SO_2 and derivative compounds:

- New-source performance standards
- State implementation plans for primary ambient air quality
- Possible new national ambient air quality standards
- Limited and controlled growth provisions within the Environmental Protection Agency's (EPA) policy for preventing significant air quality deterioration
- Potential sulfate control standards

NSPS at 0.6 $lb/10^6$ Btu sulfur in coal is a likely upper bound on control requirements. The next three strategies listed are projected to result in a sulfur limit of about 0.4 $lb/10^6$ Btu. Although much less certain, control of sulfates could further reduce sulfur emission levels to about 0.2 lb/10^6 Btu (and also call for control of precursors such as trace metallic catalysts and ammonia). In sum, a reasonable expectation is that sulfur levels must be controlled, on average, to 0.2–0.4 lb/10^6 Btu by the year 2000.

It should be noted that today's strategies and standards apply only to the direct firing of coal. There are no formal emission regulations for coal conversion processes or for power plants fueled by their products. However, in at least one case (Lurgi dry ash gasification and cleanup trains for synthetic natural gas [SNG] production), EPA is considering even more stringent requirements that would call for emission levels comparable to those from the resource replaced (natural gas). The implication is that separate control requirements might be placed, for example, on a gasification or liquefaction plant (considered as a refinery) and on a power plant fired with synthetic gas or petroleum-type fuel. Certainly, this would add significantly to the processing costs for fuel conversion. However, in its study EPRI adopted for each conversion process a range of sulfur removal capability that can achieve the 0.2–0.4 lb/10^6 Btu sulfur level also assumed for direct-fired plants.

COAL QUALITY AND SULFUR REMOVAL

Annual production of 1500 million tons of coal by the year 2000 is an assumption of the study. The logistic implications for production, processing, and transportation are neglected. So is the competing or overlapping demand for perhaps 850 million tons of coal to be used in synthetic fuel production (SNG, solvent-refined coal, low- and intermediate-Btu gas, and petroleum-type fuels). Some of these would be available to electric utilities, but production "splits" have not been estimated. The focus is simply on the sulfur quality of the coal.

Perhaps 100 million tons of low-sulfur eastern coal will be available to utilities each year, and from 300 to 600 million tons of low-sulfur western coal. Low-sulfur coal is considered to be less than 0.5 percent by weight; it runs about 8000 Btu/lb, so its sulfur quality can be expressed as being about 0.6 lb/10^6 Btu. It is thus considered capable of meeting today's new-source performance standards without sulfur control measures.

The balance of the coal expected to be needed in the year 2000 will be about 800 to 1100 million tons each year. It will be high-sulfur (2.5–3 percent) coal, running about 12,000 Btu/lb and, therefore, between 2 and 2.5 lb/10^6 Btu. Today's utility coal (overwhelmingly the high-sulfur variety) averages a sulfur content of about 2.4 lb/10^6 Btu. Assuming the same average in 2000, the sulfur removal requirement is 83–92 percent to attain likely regulatory levels of 0.4 to 0.2

Of the estimated 1500 million tons of coal in the year 2000, some 150 million tons will be burned by the 10 percent of power plant capacity still exempt from emission controls. Of the balance, some 350–650 million tons will be low-sulfur coal requiring only minimal beneficiation. This leaves 700–1000 million tons of high-sulfur coal likely to need extensive cleaning or conversion. The average sulfur removal requirement for that coal is in the range of 80–90 percent.

Stated simply, 80–90 percent removal of sulfur will be sufficient to meet projected SO_2 standards between now and 2000. This is extremely significant because it implies that flue gas desulfurization with today's wet alkali scrubbing process will remain adequate throughout the same period. (Wet alkali scrubbing carries with it, of course, the need for either a sludge ponding area or some means to dispose of wet slurry.)

ESTIMATING CAPITAL COSTS

The yardstick of direct comparison of alternatives takes shape in the dollar estimates of total power plant cost (Figure 3.2). Consistency is the key, yet it is difficult to achieve when estimates come from different sources (as in this study)—even though many of the sources are conceptual design studies performed under EPRI sponsorship:

- Gasification, by Fluor Engineers and Constructors, Inc.
- Solvent-refined coal and petroleum-type fuels, by Ralph M. Parsons Co.

- Low-Btu gasification, by Combustion Engineering, Inc.
- Direct coal firing with wet alkali scrubbing, by Ebasco Services, Inc.

Other basic data came from a number of individual manufacturers. Notably, the estimates for atmospheric fludized-bed combustion were supplied by General Electric Co. from its preliminary report on the National Science Foundation's Energy Conversion Alternatives Study (known as ECAS).

The estimate for a coal-fired plant with wet alkali scrubbing (and on-site sludge ponding) was used for normalization: Ebasco's estimate was compared with others by Combustion Engineering and by General Electric (for ECAS). This estimate assumed the use of eastern coal with 3 percent sulfur content, and all basic plant cost estimates fell within a range of 2 percent.

Figure 3.2 also lists design heat rates assumed to be attainable in baseload operation. (For intermediate load operation, as in daily cycling, the heat rate was assumed to be 5 percent higher.) Other vital assumptions were:

- Conventional steam plants—2400 psi, 1000° F superheat, 1000° F reheat conditions
- Combined-cycle plants—2200° F gas turbine inlet temperature and 16:1 pressure ratio, coupled to a 2400-psi, 1000° F steam bottoming cycle

Base capital cost for each plant is given in mid-1975 dollars per kilowatt. In each case, this figure consists of total construction cost, including contractor's overhead and fee, land cost, and owner's head office costs. It excludes contingency, escalation, and interest during construction. A contingency was then added, the amount depending on the degree of definition—for example, 10 percent for a coal-fired plant but 20 percent for a stack-gas scrubber.

The accuracy of estimates was considered separately and a range, or band, of uncertainty was assigned. Understandably, wider bands of uncertainty were linked with the less well-defined options that are still in early development. By adding or subtracting uncertainty figures, upper and lower capital cost estimates were obtained. Interest during construction, together with startup costs, was applied to each of these plant costs at a rate of 30 percent. (The combined-cycle option using petroleum-type fuel is an exception; a rate of 22 percent was used because of a significantly shorter construction period.) The total cost column in Figure 3.2 gives the probable range of capital requirements for each plant.

Capital costs for the solvent-refined coal and petroleum-type fuel options do not include increments for their respective coal liquefaction plants. Costs associated with the liquefaction processes are incorporated in the fuel costs.

ESTIMATING BUSBAR POWER COST

The ultimate unit of measurement on this yardstick of coal utilization technologies is mills/kWh, the busbar cost of power from each candidate. Values were calculated for both baseload operation (at 0.65 capacity factor) and intermediate or cycling operation (at 0.35 capacity factor).

Busbar cost comprises both fixed and variable charges. A fixed charge rate of 18 percent per year was applied to the range of capital costs derived for Figure 3.2. (Current utility experience varies around the U.S. between about 15 percent and 22 percent.) This covers interest on debt, return on equity, depreciation, insurance, and federal, state, and local income and property taxes.

Figure 3.3 compares busbar power costs for several processes. The ranges of busbar power cost for coal fuel technologies are most easily compared in groups: four options for direct coal firing, two liquefaction processes, and four gasification processes. In each group, the present—or most nearly developed—option is at the left. Thus, among the direct-firing options, each results in successively more costly power than power from low-sulfur coal without controls. Among the gasification processes, however, the more advanced—and, at the moment, more uncertain—versions produce markedly cheaper power.

Variable charges include the costs of fuel, chemicals, and operation and maintenance. Two levels of coal cost were investigated, $1/10^6$ Btu and $2/10^6$ Btu, but only the former, which is representative today, was used in the computations for Figure 3.3 (An exception is the case of direct-fired low-sulfur coal, estimated to cost $1.25/10^6$ Btu because of delivery charges.) Raising the coal cost across the board would increase plant fuel expense by varying amounts, depending on the heat rates of the different options.

Fuel costs for the solvent-refined coal and petroleum-type fuel options are based on high-sulfur feed coal at $1/10^6$ Btu, but they also include plant charges for liquefaction. Recent cost estimates for such plants are $2.50–$2.75/10^6$ Btu and $3.50–$3.75/10^6$ Btu, respectively.

Chemical costs were found to be negligible for most plants (0.1–0.2 mills/kWh), except for the coal-fired plant with wet alkali scrubbing and the atmospheric fludized-bed combustion plant. In the latter case, for example, stoichiometric requirements for sulfur removal are uncertain but range between 0.3 and 0.6 ton of limestone per ton of coal. Since the cost of limestone itself varies from $5/ton to $20/ton, the resulting range of chemical cost becomes significant, and two levels were computed for use with the high and low busbar cost estimates, respectively.

Operation and maintenance costs were estimated on the basis of plant complexity, ranging from 2 mills/kWh for direct coal firing (without stack-gas scrubbing) to 4 mills/kWh for a combined-cycle plant with coal gasification. For intermediate cycling service, all operation and maintenance costs were assumed to be 0.5 mill/kWh higher than for baseload operation.

READING THE YARDSTICK

It is perhaps no surprise that direct-fired low-sulfur coal comes in with the lowest busbar power cost for both baseload and intermediate operation: 25–28 mills/kWh and 36–41 mills/kWh, respectively. Nor is it unexpected that high coal costs tend to favor options with lower heat rates—generally, the combined-cycle plants.

But the most telling conclusion of the study, to date, intimately related to projected emission standards and foreseeable needs for sulfur removal, is that direct firing with wet alkali scrubbing, a technology almost fully developed today, is the second most attractive baseload option, at 28–34 mills/kWh with high-sulfur coal.

Other findings (all apparent in Figure 3.3) are: (1) busbar power costs for baseload operation are in the 25–40-mill range, except for Lurgi low-Btu gas and petroleum-type liquids fueling conventional steam plants; (2) regenerative scrubbers, advanced gasifiers (beyond the Lurgi), and atmospheric fluidized-bed combustors are all comparable for use with conventional steam plants—and only slightly more expensive than plants with wet alkali scrubbing—for either baseload or intermediate duty; (3) only the combined-cycle versions of advanced gasification processes show promise of being less costly than low-sulfur coal; (4) combined-cycle plants using petroleum-type fuels and medium-Btu gas from advanced gasifiers have comparable costs for intermediate service; (5) atmospheric fludized-bed combustion looks attractive in baseload operation, but there is significant uncertainty in its economic performance.

USING THE YARDSTICK

The payoff from this study is not the economic benefit that any utility can get by adopting the "winning" coal technology. The payoff is in the better shaping of R&D emphasis in EPRI's direct coal utilization and coal conversion programs. Six examples suggest the ramifications:

1. New funding is being allocated to research on scrubbers, because they are the most economically attractive prospect for plants that must comply with tighter SO_2 emission standards. Reliable operating procedures for wet alkali scrubbers (to overcome corrosion, fouling, and plugging) should improve their availability and cut maintenance charges by one third. For regenerative scrubbers, which require less land area for waste disposal, the aim is to develop practical process alternatives meeting a range of utility needs. (Different process by-products are salable in different regions.)

2. More attention is being given to total plant requirements, all the way from raw coal to busbar energy. It's a system view rather than a narrow focus on one or another coal conversion technology. And it is particularly pertinent for solvent-refined coal and petroleum-type fuel processes. For example, EPRI is exploring how such fuel processing costs might be cut by modifying gas combustors and gas turbines so they can accept lower quality fuels.

3. Two major coal liquefaction processes, H-Coal (Hydrocarbon Research, Inc.) and Donor Solvent (Exxon), are getting the thumbs-up sign to produce both utility fuel oil and gas turbine fuels. EPRI plans major funding to support the operation of large pilot plants (250–600 ton/day) for both these processes. In contrast, major pilot plant support is not planned for any other process that yields petroleum substitutes from coal.

4. Coal gasification integrated with a combined-cycle plant remains a high priority because of the need for operating experience with this technology. Three coal gasification schemes are taking favored positions for further EPRI R&D attention: the slagging moving-bed gasifier (British Gas Corp.) and the partial-oxidation entrained gasifier (Texaco), both for combined-cycle plant application, and the atmospheric, two-stage entrained gasifier (Combustion Engineering, Inc.) for fueling a conventional steam plant. Research efforts on other advanced gasification systems are being cut back.

5. EPRI's fluidized-bed combustion research is now focused on the atmospheric-pressure process, and a test facility is being built. The pressurized FBC concept is being minimized.

6. The importance of reliable gas-steam combined-cycle power plants is newly evident and getting attention. One major new effort for EPRI has been the work with utilities and suppliers toward demonstration of an air-cooled gas turbine that can operate in the temperature range of 2100–2300° F.

IS COST THE ONLY YARDSTICK?

The seeming simplicity of EPRI's "first cut" at analyzing coal technologies suggests the question whether cost is the only yardstick. The answer is yes, but only because it is so nearly universal a way to recognize many variables. A better question seeks to clarify the cost of *what*.

This article—and up to now the EPRI analysis it portrays—has focused on the cost of one factor alone: sulfur removal. The criterion for the various options was only their design capability to meet projected sulfur control levels of 0.2–0.4 lb/10^6 Btu with coal having a 2.5–3.0 percent sulfur content (2–2.5 lb/10^6 Btu).

What must be emphasized is that many other important variables, and their inevitable effects on costs, have knowingly been omitted in the interest of simplicity and so that an R&D guidance scale could be quickly assembled. One example is NO_x control. What will be required? How widely? When? By what process means and at what cost?

Similar questions can be asked about siting restrictions, cooling water requirements, and waste disposal, to name a few. Always, the bottom-line question is "At what cost?" As more of these variables are researched and included in the estimates, the busbar power costs will change, and perhaps even the relative ranking of options.

Despite their favorable ranking on the basis of sulfur removal cost, wet alkali scrubbers may not retain their advantage as other coal technologies show the need for less land area, or a smaller volume of cooling water, or as they exhibit lower overall heat rates (which some already do).

Mid-term commercialization (that is, between 1985 and 2000) is now the earliest foreseen for even the most promising coal options. Today's simple screening, based solely on the cost of sulfur removal, enables a more focused, efficient allocation of R&D funds. As the cost implications of other factors are included, the resultant fully documented research will reveal the best choices for clean coal utilization.

MODELING FUTURE CAPACITY

The existence of consistent, directly comparable cost data for coal conversion technologies enables some interesting modeling, too. It's one thing to use the figures for direct comparison of isolated plants. But it would be more meaningful to see the effects of utility system interaction. EPRI is therefore using its study data as inputs to a half-dozen representative utility system models that will expand in generating capacity by selecting the technologies that yield minimum incremental power costs. Since these expansion models closely simulate utility systems throughout the United States, it should be possible to better assess the potential for each technology in a future national generation capacity.

The modeling should also help to answer a perennial question about R&D leverage. The new coal conversion and power generation technologies, as selected by the operation of the expansion models through some period of time, can be identified and assessed, and their total economic benefit to the national energy picture can be estimated. Comparing the benefit to the R&D cost gives the leverage, another tool for figuring priorities and establishing funding—possibly for the next annual updating of this benchmark study of clean coal and what it costs at the busbar.

Method	Sulfur Removed, %
Direct firing, pulverized low-sulfur coal	none
Direct firing, pulverized high-sulfur coal with wet alkali scrubbing and on-site sludge disposal	80-90
Direct firing, pulverized high-sulfur coal with regenerative scrubbing (using hydrogen produced on site) and reduction of gas to elemental sulfur	90-95
Direct firing, pulverized coal in a fluidized bed at atmospheric pressure with dry limestone added to the bed	80-90
Direct firing, pulverized solvent-refined coal	70-90
Liquid firing, petroleum-type fuel	90-95
Low-Btu gas firing (100-150 Btu/scf) after gasification in moving-bed, dry ash Lurgi gasifier and Selexol process for acid gas removal	>95
Medium-Btu gas firing (~300 Btu/scf) after gasification in slagging moving-bed gasifier and Selexol process for acid gas removal	>95
Low-Btu gas firing (100-150 Btu/scf) after gasification in atmospheric, two-stage entrained gasifier and Stretford process for acid gas removal	>95
Medium-Btu gas firing (~300 Btu/scf) after gasification in pressurized, two-stage entrained gasifier and Selexol process for acid gas removal	>95

TEN CLEAN WAYS TO BURN COAL
FIGURE 3.1

	Heat Rate, Btu/kWh	Base Cost, $/kW	Contingency, %	Uncertainty, %	Total Cost(a), $/kW
Conventional Steam Plants					
Low-sulfur coal	9,000	PP: 290	+10	±10	375–460
High-sulfur coal with alkali scrubbing	9,500	PP: 290 SR: 50 : 340	+10 +20	±10 ±20	485–625
High-sulfur coal with regenerative scrubbing	10,000	PP: 290 SR: 150 : 440	+10 +20	±10 ±20	575–740
Atmospheric fluidized-bed combustion	9,500	PP: 340	+20	+25, −15	450–665
Solvent-refined coal	9,000 BC: 10,000	PP: 290	+15	±15	375–500
Petroleum-type fuel	9,000 BC: 13,400	PP: 190	+10	±10	250–300
Low-Btu gas, moving-bed, dry ash Lurgi process	BC: 13,600	PP: 190 SR: 390 : 580	+10 +20	±10 ±15	760–1,000
Medium-Btu gas, slagging moving-bed process	BC: 11,300	PP: 190 SR: 255 : 445	+10 +20	±10 +20, −15	585–800
Low-Btu gas, atmospheric, two-stage entrained process	BC: 10,600	PP: 190 SR: 210 : 400	+10 +20	±10 +25, −15	525–710
Medium-Btu gas, pressurized, two-stage entrained process	BC: 9,800	PP: 190 SR: 155 : 345	+10 +20	±10 +25, −15	490–600
Combined-Cycle Plants					
Petroleum-type fuel	7,500 BC: 11,200	PP: 160	+15	±15	185–250
Low-Btu gas, moving-bed, dry ash Lurgi process	7,500 BC: 9,500	PP: 160 SR: 335 : 495	+15 +20	±15 ±15	650–875
Medium-Btu gas, slagging moving-bed process	7,500 BC: 9,100	PP: 160 SR: 215 : 375	+15 +20	±15 +25, −15	490–695
Low-Btu gas, atmospheric, two-stage entrained process	7,500 BC: 8,400	PP: 175 SR: 180 : 355	+15 +20	±15 +25, −15	460–650
Medium-Btu gas, pressurized, two-stage entrained process	7,500 BC: 8,150	PP: 160 SR: 130 290	+15 +20	±15 +25, −15	375–530

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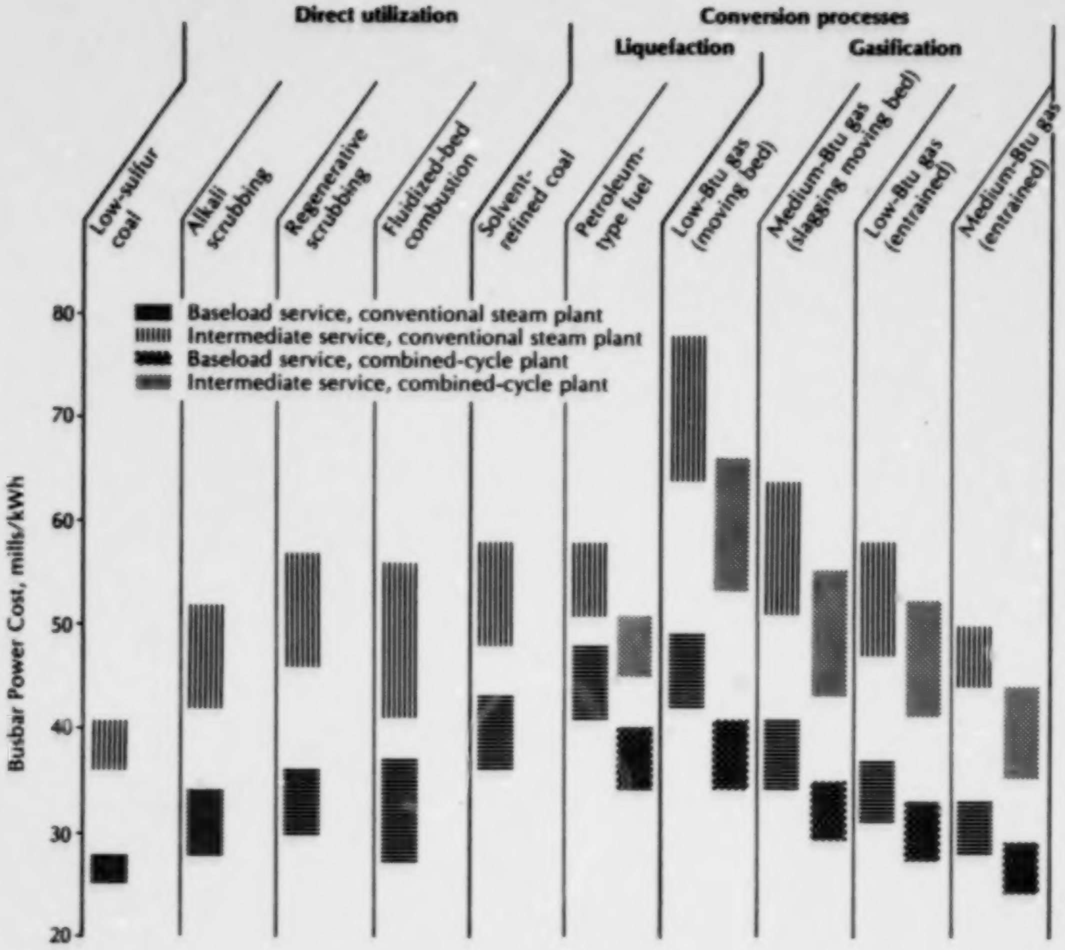
[a] Includes IDC and startup at 30% (except 22% for combined-cycle petroleum-type fuel plant).

PP = power plant.
SR = sulfur removal system.
BC = basis coal (coal conversion and power generation).

CAPITAL COSTS FOR TEN CLEAN WAYS TO BURN COAL

FIGURE 3.2



COMPARISON OF BUSBAR POWER COSTS
FIGURE 3.3

REGIONAL AND INSTITUTIONAL PERSPECTIVES

Joseph Mullan
National Coal Association

(Ed. This talk was transcribed from a tape recording. Certain passages have been omitted where words could not be understood and, as a result, the meaning of a whole sentence or passage was unclear. Omissions are noted in the text either by an editorial explanation or a series of periods, i.e., . . .)

This program is an attempt, I think, by EPA to keep me off the floor of the House of Representatives today, where certain provisions of the Clean Air Act are up for vote this afternoon. So, if suddenly you see somebody come to take me away, that somebody has decided that I have to go over and work on an amendment. We've got a little concern for what's going on over there right now, obviously. (Ed. Several sentences regarding energy hearings are omitted here.)

I'm sorry I missed this morning's meeting, because I understand that eight left and others stayed in their room and I have personal friends who did a pretty good job of telling you everything I was going to tell you this afternoon. I didn't have the foresight to take a look at what he (Balzhiser) was going to say. So, at 11:00 this morning I had to hurry and redo what I was going to talk to you about. Someone mentioned to me that Dick Balzhiser pretty well took on EPA. That's a fun thing. I'm sorry I wasn't here; I would have enjoyed doing that myself.

Usually they sack Frank from a hearing either physically or mentally. But no, we can still talk to each other. In fact, Frank and I leave here today to appear at a hearing tomorrow on new sorts of performance standards. Really, we've worked with performance standards which fit pretty close to the subject you have today—coal cleaning. These sort of performance standards, at least in their present context (and I'm not going to try to guess what Congress is trying to do with them at the moment) . . . would include the use of coal cleaning as a means to the best available technology.

I had, as I say, taken a different look at the presentation this afternoon while reading a presentation this morning. I had taken a look at the regional and institutional perspective; looked at them in my own mind as a regional and institutional problem that we have in the industry. The kinds of problems that we are faced with, while most of them are regional, end up being national problems. Industry, while it is fragmented to a degree between Western situations and Eastern situations, because of the analysis of the coal sulfur contents, has problems that are really national in scope. We don't solve some problems by transporting coals back and forth across the country. At least we don't seem to as of yet. The thing that really worries me is that every time somebody comes up with a new solution to a problem, I end up finding two more regulations saying I can't do it that way. EPA seems to be a leader in that group, I must admit, but they're not alone.

There are a couple of other agencies to help us a bit. For example, the subject in discussion today—coal cleaning. Coal cleaning is obviously not a new answer to reducing pollution but is a result of coal utilization . . . But it itself is the center of controversy within EPA.

A little problem with EPA work. (Ed. This passage is unclear, but referred to those on one hand concerned with air and those on the other concerned with water.) There is a place in the middle where the lawyers try to keep from killing each other, I think most of all. I have a problem . . . I have the people on the air side looking at coal cleaning and doing a lot of work on coal cleaning. And we, the industry, go out and say, "Alright, we are going to go out and build a coal cleaning plant". Along comes the other side of EPA, the water group, who say, "Now wait a minute. Before you do that we think we better have some regulations on what comes out of that plant". We have ended up with some regulations on the water side that are beautiful. No discharge from the plant—an interesting phenomenon. I've never seen a plant do that. It may rain occasionally; things of that nature can come along. I must admit I think we have EPA's attention and we have got to a circuit court in Richmond to get it, but we have their attention at least . . .

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Every time we get a solution we get another problem. Now when we're with them they say, "Well, all right." That's fine. Now all new plants are going to require an environmental impact statement. Now this has created a real problem for the people on the air side, because three companies that I know of personally have said that they're going to have to build coal cleaning plants that reduce the coke or the ash going into a particular utility plant. They make applications for the firm that builds the plant and the EPA Region II says, "Fine, but you have to do an EIS". And the bureaucracy to do an EIS represents a 17-1/2 month delay. So, you go to a bank in Charleston and say, "Well, we are going to build this plant but we want to delay it for 18 months because of having to go through all these form approvals". Of course at the end of 18 months we might not get an approval. You get a very cold reception when you get to a banker in Charleston or Philadelphia or New York or anywhere.

So we had to find some way to solve that problem between the two powers at EPA. Because, granted, you're burdened with an EPA act that says under certain circumstances you have to do an EIS. There has to be a better system than we have had to date.

By the way, that 18 months does not include any law suits . . . I guess usually a Sierra Club suit or two, or something of that nature could add about 2 or 3 years to the situation.

When we start looking at this whole issue of coal cleaning don't sit back politely and say, "Allright, coal cleaning is good. We should do it. We could improve ways to do it. Now, why don't you the coal industry go out and do it?" Realize that there is a . . . constraint from me being able to take that good thinking and the people from technical areas and applying them practically from the standpoint of getting a permit to build a plant. One that I am particularly familiar with is the grounds and levels, the cracks or ends. When filing, they just got in under that new course performance standard that came out and it created a problem.

In fact, I mentioned about that track record not being too good. I guess Dan Snyder in EPA is not here. Dan is a pretty good friend so I'll take a shot at him while he is not here and anybody who knows him can tell him about it. We have a little problem with EPA. We had 2000 permit requests that got lost. In fact, they were down in a cardboard box in a hall there. They were found right after the environmental group in West Virginia sued EPA and us—or at least notified that they were going to sue us—for operating without permits and EPA for allowing us to operate without permits. Our counsel told us that we had exhausted all of our administrative remedies by making applications to determine the continuing operations. Surprisingly they found the cardboard box, and the permits started coming out in a hurry after that.

When I'm critical of EPA, it's with some reason and I'm concerned. It may be that EPA is not adequately staffed. I must admit I think its adequately staffed in some areas. (Ed. There was a statement here about environmentalists completing forms required of others.) In fact, that might be an interesting insight for them to find out what it takes to do an EIS. Just going through the social-economic impact is enough to give you gray hair.

That is just one constraint on building of a coal prep plant. I think it's a pretty doggone realistic constraint—that 18-month delay—going out to get the money. When I took a look at my role in this conference, as I say, I was looking at it more as related to the constraints on the industry or constraints on coal cleaning. And as I look at the situation, I look at Dick Balzhiser's presentation this morning. I found that he too appreciates the constraints on the industry. While he talked about constraints of the industry, let me take a look a little bit more into constraints on utilizing coal cleaning. What are some of the problems of coal cleaning? What are the problems related to it?

It's real easy to find a lot of problems on almost any subject. What have we got now—about 120 people in the room? I probably have one for each of you. Just to give you something to go home with, and I think that's the important thing, a handful of problems is an easy way to remember them. You know tomorrow morning you get up and some shave and some put on their lipstick or something of that nature and take a look at that hand and, just maybe, you can think of our problems—at least one of the handful of problems that we have here. Just take five of them. Five easy, simple things that we should be able to solve in the industry but that will have an impact on prep plants. Take areas: money, routine, manpower improvements, markets, the whole works.

Money. We sort of hate to mention the fact that we are going to have to spend something between $21 and 25 billion to open new mines. And, of course, add to this the money that is going to have to be spent to open up railroads, and factors that are unknown—an unknown that we haven't really taken a look at yet—and that is the amount of money to open up preparation plants since they are considered a part of the whole cycle. We don't know what that number is going to be, but one thing that we are sure of—it is going to be sizable. We are talking about doubling the size of the industry, which puts out 650 million tons now, and depending on whether you agree with Mr. Carter or disagree, will be something around 1.1 billion ... Everybody keeps telling us that we are going to get our 1.1 billion tons of coal and then we start throwing constraints to going out and getting it.

I have a little problem myself with trying to think that we are constrained from some of the other fuels, particularly those that we import. One of the things we should really be concerned with in that whole money structure is the fact that is certain to be made by some members of the Congress, relative to suggesting that the oil industry should divest themselves of the coal industry. And I tell you, you spend about a day in our office, and you talk with people in the coal industry and you will soon find out that the important things the oil industry brought to the coal industry were (1) dollars and (2) scientific challenges. We are a going industry with $6 or 7 billion. That kind of industry can't expect to make that $21 billion ... requirement without having some influx of dollars. Frankly, we in the coal industry see nothing wrong with that influx of dollars ...

In fact in talking about dollars, I think that we have to say something about manpower. Industry, of course, has the manpower problems. Maybe we can expand a little bit about what Harrison said this morning. One of the problems that I see is the fact that we have a group of people that were working for the industry about the time your ... came along. Following that period, no one came into the industry until about 1970. But we have quite a few people in the industry that are about 45 years old up to 55 years of age, maybe even 60. Then there is a void and we have a lot of people that are between 21–32,33 years of age. If any of you run a company or organization or agency you know that middle management has got to come out of that group of people that we don't have right now. The time of decision making is what we are talking about... Do I go to coal cleaning? These are decisions that have to be made by people specifically in that middle managers' group and we are sorely lacking in those people.

So, while we were getting some money from the oil industry, we started to get some of their scientific capabilities but we also got some management capabilities that way. Now granted, they don't know coal mining and they don't know coal preparation, and coal transportation. But I didn't either. (Ed. Mr. Mullan alluded briefly to his background, all of which was not clear.) If you have a good engineering background, it really doesn't matter if it is getting you interested in the subject. In fact I was interested in the discussion over here just before the meeting began, I think that mine was the only bio that didn't say nuclear engineering on it. And I said, "Well, that is a pleasant surprise". (Ed. There was a brief allusion at this point to an experience with the location of a nuclear plant.)

We are going to need some manpower for the mining of the coal. We are also going to need manpower with coal prep plants. The coal prep plant industry in the United States, if you look at the curve over the last 15 years, is sort of bending over. The utility industries obviously were concerned with dollars and they were looking at raw coal. They were not too concerned with cleaning the coal. They figured that they could clean up their problems at the plant. In fact, we went from a fair portion of the steam coal being cleaned to very little of the steam coal being cleaned; so it was dollars and cents, to keep in that type of a market. So, if we are going to start talking about coal cleaning techniques and coal cleaning facilities we have to start talking about people with knowledge ...

We have a little problem. I don't know that many people who know how to run a coal-fired power plant. I have made this point to people in the operating units, to staffs of utility plants and industrial plants. You know that it used to be, a little before I started in the business, that you went down to the local ... and for $10 picked up a guy who could grab a shovel and throw coal into a furnace. And, if he didn't blow it up you were lucky.

We are talking of a totally different ball game today, if you are going to start putting coal back into industrial sites, industrial plants, and utility plants. And just as important is manpower to mine the coal and build the scrub plants. You have got to have adequate manpower that knows how to burn the coal. In fact you better throw in someone who knows how to design the coal-fired power plant because you can't find too many facility engineers who know how to do that.

One of the things that we are stressing, and we might ask your support, is the expansion of efforts by Federal government and by others, to see that the mining pools get some of these dollars, so that we will have new miners and new people coming into the industry. We also ask any of your support in the areas of training programs. Yesterday, I ran into a young chap from my home town—a friend of my son. I guess that he is about 21 years of age and he is working for a mine in southern Ohio right now. It is interesting to me to see a bright young kid just our of school who has gone to work in the coal industry. I asked him why did he choose that particular job and he said, "Well, there is one simple reason. I couldn't find anything else that would pay me $60 a day". That ain't bad.

We are interested and have something to offer. If any of you are interested or have the type of training that we need in the coal industry, I suggest that you get a hold of us. We are always looking for people, and there are training programs within the industry. For that matter, those of you from academia, we beg your support in trying to get better programs and expanded programs in mining engineering.

Just briefly, on a couple of these other constraints. You know what is a constraint to me is this whole issue of transport of these coals. It factors in on the issue of coal cleaning. You know, in view of the utility executives getting the middle of Ohio, and saying, "Well, I have a power plant that needs to meet some standards, whatever they happen to be, and I have the option of getting some coal that can be cleaned down to meet performance standards. I could go to a plant and install some kind of emission controls. I could take a look at going to Western coals". You start making those options. And you need to take a long look at that transportation situation. I have been fascinated in watching those transportation situations, having grown up in the northeast and watching the northeastern railroads go downhill in a hurry. I was fascinated in circumstances developed over here in a plant the other day. They had a new phenomenon occur—they had something called stationary derailment. The train was sitting and waiting to go in and they fell off the track.

Now if you are going to expand coal to any extent, we're talking about today, we better make sure we have a way to get it there ... But it is not just the railroads. In particular we're talking about Eastern Railroads, which fell into disrepair. I hear all of the stories from Conrail and they tell me they're building hundreds of miles of new track. And we are looking at thousands of miles of disrupted track. I start looking at transportation modes of about 7 to 8 miles an hour. Seven to eight miles an hour—that is about the most that you can get out of trains on Eastern railroads. New trains are the greatest. With new trains the concept was that you load coal in the mines today and deliver at the facility tomorrow, then we get the car back in the mine. A lot of utilization of the car. It is a good 4 days in the plant, except that the train leaves the top of the mine 8 days later, in some cases 7 days later, and arrives carless. We were doing better than that when we used single cars and lost them in the ...

I don't know what they are doing with commuter trains now with the 7 mile an hour situation. Maybe what we need there is a 55 mph speed limit—no less than, as opposed to not more than. Our moving problems are not restricted to railroads. We do have problems relative to pipelines or whatever. Pipelines to me offer interesting circumstances to talk about coal cleaning detergents. Most of the work that I have seen on coal cleaning was a really ... job on sulfur. Because you take the coal and crush it down to pretty fine sizes and then put it into an open-top hopper car and then try to deliver it. And, you lose a little on the way ... Yet with the pipeline, you have the possibility of putting these two things together; coal cleaning and fine coal delivered to the power plant.

I was involved in one such project myself personally and that was the one that took coal to a ... The original pipeline ran from Cadiz, Ohio, up to Cleveland. Most people have only heard about that part of the pipeline. They didn't hear about the part where we put it all in a barge and took it over to New Jersey ... We did send slurry coal in a barge from Cleveland to Perth Amboy, New Jersey, and burned it in a power plant. And it was coal that would be not unlike what you might typically be getting out of a scrub plant.

These are just some options that occur if you start putting the concept of coal cleaning and coal transportation together and try to make some sense. I realize that we are immediately going to be faced with the environmentalists that say you are not going to touch my water in the west, or something like that. Maybe that's not the place to use that particular set of circumstances, but there are some other alternatives that should be looked at.

What is interesting to me to see is that there is 50 percent division in the environmental community on pipelines—one group saying it is a lot nicer to run a pipeline through a valley and revegetate the area and you really don't see that it was bare and it doesn't really bother the environment. Nothing like what a hundred 100-ton trains would do to that community in the way. I've got a little problem about those hundred 100-ton trains. If my mother-in-law lived on the other side I would probably like it. If my wife lived on the other side, it would probably take more. But I really think that some of those communities have to face up to the problems that we're talking about . . .

Utilities are calling upon 400 million tons of coal right now and utilities are expanding another 400 million tons, so that somewhere around 800 million tons of coal will be going to the utility industry in 1985. Now from 400 to 800 sounds like an awful lot. Now the industry had to go great guns for that. We haven't been sitting back idly nor has the utility industry been sitting back idly since Mr. Nixon's Project Independence and some of the other things came along. Right now there are 250 new units on the books which could use about 370 million tons of coal. So, we really feel that Mr. Carter's proposal may be the beginning of a challenge. If he really wants to challenge us, he's going to have to try a little bit harder.

Now granted, there is a real challenge to place 250 new units all over the country. We are concerned whether those 250 units can attract new coal and can use it in a manner that is acceptable to the environmental communities. Much is being said right now about availability of control technology, coal cleaning, coal fuels, things of that nature, in order to meet it. We feel that there is one variable that has been left out of this whole formula, and that is the variability of sulfur in the coal itself. Particularly, we are talking about washed coal. Particularly we are talking about coal we can burn in a power plant. It's very easy to stand up and say that there is no problem meeting 1.2 lb SO_2 regulations and at the Eastern power plant you can scrub it. Now remember, when you read the rest of the regulations the EPA has out, it says that you shall monitor that plant—two hours of monitoring in a 3-hour period and you shall not exceed that 1.2 number during that period. And, you are to file all exceedings of that rate with EPA. Now I can just see this—utility companies filing those. I looked at some data that came out of a utility company on a 24-hour average, and the plant violated three-fourths of the year. All they need is for the EPA, or any of those people, to really start looking at some of these things and suddenly realizing that we have a much larger problem than people realize. Sure, we are averaging something less, the utilities are averaging something less, than 1.2 lb SO_2. But the problem is that, I think the 1.2 lb number started as . . . itself . . .

The problem that I have is that a lot of the data in these types of documents are based on pretty widespread sampling. For example, we were talking about one just before I came up here. With the sampling, it is probably on 5-mile centers in an area out in Montana and EPA is telling me that the coal is able to meet the new source performance standards of today. Well, I have a little problem. When you start monitoring an area on 5-mile centers, you are not talking about 3-hour limitation. You are talking about an average of a year or averaging of years. If you happen to hit the area where the sulfur ball was, or you happen to hit the area where it's particularly clean, you would take that one test book. We can give you a pretty good idea of what the average sulfur content will be over the life of the mine, or even be a bit more precise and narrow it to a number of . . . But try to then take that kind of information from this buildup, well, say 80 percent removal from that average sulfur content. It means that you would still have a number which is an average.

We have been looking at some of these numbers as they relate to the 1.2 number or the 0.6 or 0.7 percent sulfur coal as the result of the calculation, and we find that in the main, what they must have meant was 30 days, even though they crank in 3 hours. Now I think that the important people end up with the 3 hours and I think that technical people in reality know that the number is, 30 days. It is a matter, I think, of continued discussion between ourselves and EPA. It is very important because when you start cleaning the coal, that degree of variability, you may narrow it just a little bit, but it's there.

Let's take it a step further and put it in the boiler and run it through a scrubber. The degree of variability of all the coal has gone in there. So you have got a lot of normal coal that looks like that. If you are using averages, then that means that half of the time you are in compliance and half of the time you are out.

What we are asking today is that . . . before they start taking a look at changing the number they better find out what the number really means and what exactly is behind it. If you are going to start looking at coal preparation plants and looking at coal preparation acts, do the same thing. Don't just look at the average sulfur content coming out of that plant. Look at what would be the impact if you were only allowed to take the typical 3-hour burn at a utility plant, like three cars a load . . . Don't sit back politely and think because you are cleaning your coal that you are going to meet these standards or for that matter if you are scrubbing the power plant you are going to meet standards. Monitoring is very critical. In most cases, the work has been done on new prep plants, contrasted to bench scale, and you don't get any of the variability. You are working with a small amount of coal. You have to look at the large amounts of coal in order to figure out the variability.

A major point of markets is where is the coal going to be. Part of that coal preparation is where is the coal going to be mined and where is the coal going to be used. Several people, as I was walking through the hall, were talking to me, saying, "Well, it's no problem. You can bring Western coal east and this is all going to be low-sulfur coal from the West. All I can say is a word of caution, if you're a consulting engineer who works with an agency making projections such as that. We have taken a look at the coal that is presently on call. By the way, that's 400 million tons that Mr. Carter wants us to increase by, by 1985. We already have about 70 percent of that under contract and we are not too concerned about it being a big new lump. Eighty-six percent of the coal that will be mined west of the 100 meridian mark . . . will be used in that area. Not a lot of that coal is going to be coming east, and yet I don't find very many people that realize that. And the coal that is coming east from that area is already coming east. It's coming into the Wisconsin area, the Illinois area, and some of it is coming into Eastern . . . A very small part of it is coming to Ohio. And that in itself is a subject of litigation right now because EPA chose to write the standards for Ohio, since Ohio apparently didn't do a good job. It was interesting. The states were required to set the pollution limits based on regional areas. In other words the power plants of Southern New Jersey had to meet the air quality needed for an air monitoring station located in Hoboken, New Jersey (a little ridiculous as far as I am concerned)—you can't learn. They learned well because when EPA went in and did the sampling and set up the programs for Ohio, EPA did a site specific. And it is interesting to me because after all of these years of battle between . . . seven AEP plants in Ohio, that were part of this Ohio program that EPA put together, are now allowed to burn up to 5 percent sulfur coal. We have to add sulfur to some of this coal in order to get it there.

So that is another thing to start looking at. When you start looking you will find out what is happening to the standards in your local area. It is a lot of overkill. The state standards are a lot of overkill in the localized areas. While it may seem that we are going to have to prepare an awful lot of coal or clean a lot of coal or for that matter we are going to have to install a lot of scrubbers, I think that you better take a long look at what is happening in the states right now. There are 14 states that are reevaluating their standards in light of things like economics, jobs, and last winter's problems with the coal. And it sort of comes out in the real world in finding out that, if we have to meet the national ambient air quality standards, the number is a lot different than what they put in their regulations today.

Now that has a very important bearing on what you do with coal cleaning. Now it may be very good for coal cleaning, because the biggest reason that I think coal cleaning was literally thrown away by we in the coal industry and by the utility industry back in about 1968–69 was because, if we cleaned the coal we couldn't meet the standards anyway. There is no sense in doing it both ways. The sense was then we couldn't clean it to meet it so we'll meet it at the tail end of the plant. But if we are going to back down and take a look at all of these standards and put them back into what I consider a much better perspective that would be necessary to meet national air quality standards for a cleaning plant, we may find that coal cleaning is an answer for a lot of these people.

And I really think that if that is the case, the coal cleaning will take place at the coal mine instead of at the utility plant. And I think the utilities will come up with these dollars and cents and will transport the gas and take it back. So there is possibly quite a market for coal cleaning that some of you may not have looked at, as a result of the fact that we will be reevaluating some of these standards.

The interesting thing to me is that where is this Western coal going to come from if you say that it is not going to come East? In my various career, I have spent a little bit of time in Texas and if someone would have told me that they were going to start bringing coal in to Texas, I would say they were out of their cotton-pickin' mind. There is no way. And suddenly I look at the chart and it says coal used in ... will go from 9 million tons in 1975 to 82 million tons in 1985—10 years. From 9 million tons to 82 million tons a year. And in the main that is only for brand new power plants. Most will be brand new because most power plants have been effective for gas or oil and there is no way that you can convert these to burning coal.

So when you start thinking about where you are going to start looking for coal in the West to bring to the East and Midwest—if you are in the Midwest, you better look at ways to burn Midwestern coal, and if you are in the East, you better look at ways to burn Eastern coal, and if you are in the West you have got to keep a lot of people happy—a lot of people know how to burn coal. (Ed. A story about development of a coal-fired plant in San Antonio, not completely intelligible, is omitted here.)

If nothing else, what I hope that I've added to your meeting is to point out that there is a role for coal preparation and a role for coal cleaning. A role that I still think is somewhat undefined. It may require the time to take a look at what standards or what levels are going to have to be met to meet the health standards across the country. Maybe instead of looking at 0.7 percent sulfur coal, and 0.8 percent sulfur coal, start to look at something like 1.7 and 1.8. Or, in the case of Southern Jersey, they are looking at 2-1/2 percent sulfur coal now as being allowed. Now you can do a lot if 2-1/2 or 3 percent is the number that you have to meet. It is a lot harder to get down to 1-1/2 ... and if the major portion of that coal happens to be organic sulfur you have problems. In fact, I am reminded of some work, and I may be critical of my own facility, between 1950 through 1965, before EPA ... If we made any mistakes at that period, it was that we weren't looking for the coal that was most likely to be cleaned. Of coarse, in Appalachia a lot of people think that all coal should be cleaned. And I have to give the EPA credit. EPA people are for the first time recognizing this problem that coal cleaning is a selective answer and a very big part of the problem is sulfur variability within the coal. In fact I have to compliment EPA. They were the ones that funded the project with Pedco that really did the job on that. Frank, I give you hell when you do things wrong, but I like people to compliment you when you do things right.

Now I just hope that the enforcement people will have the power over your find and they will at least listen to the technical people in North Carolina. Because the people down there are starting to realize that these are real factors. Industry I think has stopped fighting these cases—if we get past that moment of truth and start talking on the same basis.

I'm reminded of the project we had in the coal industry on water. We fought with EPA for a long period of time with the scrubbers ... If you want to argue about the scrubbers you go talk to the utilities industry, but when it comes to coal, I'll argue with you on about any subject. But the area of ... control, we sat down with EPA when the project began and the one thing we asked was for a sample. It was interesting at the end of the project, we knew what they knew and they knew what we knew. It is a big difference.

I would hope that we could take that same degree of learning and transpose it over to the air side, particularly over to this area of coal cleaning. Let's find out where coal cleaning has complications, what coals it can in fact be used with ... and find out what standards are necessary to meet the national ambient health standards ... some other forms. Just getting to that point is a big improvement, and I think that it is something that we have not done today.

ENVIRONMENTAL PERSPECTIVES

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INTRODUCTION

As indicated by previous speakers, the President's goals for coal are to produce one billion tons annually, essentially doubling current production levels, and to encourage industrial consumers to shift to coal instead of gas and oil. At the same time, presumably there is to be no change in plans with respect to pollution regulations as they affect the use of coal—if anything, they are apparently to become more strict.

This last presentation of the afternoon will include a brief analysis of coal itself, and then review the effects of sulfur dioxide on health and welfare and the status of current regulations. The technology being employed around the world and the institutional constraints on its use will be discussed. An economic analysis of the proper roles for physical cleaning, chemical cleaning, and stack gas scrubbing will be outlined. In conclusion, coal cleaning will be shown to have a critical role in the future of energy, but the world still needs help in a sensible definition of this role.

Coal cleaning, because of established use, relative low cost, ability to remove much of the sulfur content of coal, and other advantages as well, must be considered as a possible strategy for increased use of coal without unacceptable damage to our environment.

THE NATURE OF COALS

Coal is the most readily available, and frequently the cheapest, fuel in the United States. Figure 5.1 shows the ultimate composition range of various coals used to generate power in the U.S. These elements make up almost entirely the organic portion of coal, although some of the sulfur actually occurs combined with the constituents reported as ash. The ash represents the mineral matter in coal and consists mainly of silicon, aluminum, iron, and calcium oxides, along with traces of most of the other elements in the periodic table. Some of these, e.g., mercury, lead, cadmium, may be environmental problems in themselves. Moisture contents can obviously fluctuate widely depending upon mining and storage conditions.

Sulfur, the component of coal under most attack by environmentalists, is not thought to be normally present in the elemental state in coal, but is almost always found combined in three different types of sulfur compounds. The three types are classified as organic, pyritic, and sulfate sulfur. The organic sulfur is bonded into the cross-linked carbon-oxygen-sulfur-nitrogen chains which make up coal. The pyritic and sulfate sulfur usually occur in the form of occlusions imbedded in the organic mass and are included in the generic term ash. The distribution of the organic sulfur is fairly uniform. However, the pyritic and sulfate sulfur can be quite concentrated in localized accumulations and this can frequently be removed by physical techniques.

The occurrence of sulfur in coal may vary within rather wide limits. Good commercial coals from the eastern U.S. may contain between 1 and 2 percent sulfur by weight. However, these low-sulfur eastern coal reserves are becoming depleted, and should probably be saved for use in metallurgical processes where low sulfur content is of first concern. Coals with sulfur levels in the range of 2 to 4 percent are generally used as the fuel for power generation in the eastern U.S., although there is a significant shift to low-sulfur western coal going on at present. The heating value of coals falls from a high of about 15,000 Btu/lb for anthracite, to lower values for bituminous, subbituminous, lignites, and brown coals, to essentially zero for peat. Many western coals have relatively low Btu contents, and some have high sodium contents, which can cause serious derating of boilers when used in furnaces not designed for these peculiarities. Since coals used for power generation have an average heating value of about 10,000 Btu/lb, each 1 percent of sulfur content in the coal generates approximately 2.0 lb SO_2/MM Btu.

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THE EFFECTS OF SO_2

Much of the alarm about the health hazards of sulfur oxides stems from publicity regarding several "episodes" in which people died during periods of extremely heavy and prolonged pollution. These occurred in the Meuse Valley in Belgium in 1930; in Donora, Pennsylvania in 1948; in London in 1952 and 1962; and in New York in 1953 and again in 1966. Some 4,000 more people died in the few days of the London episode in 1952 than would normally have succumbed in a similar period of time. These "excess deaths" are usually blamed on the high levels of SO_2, though the smog at the time contained many other pollutants.

Actually, the effects of sulfur dioxide on vegetation, on the corrosion and disintegration of structural materials, and on man have been under investigation for many years, but the results are not always consistent and much controversy still surrounds the data. As shown in Figure 5.2, in low concentrations (up to 0.01 to 0.02 ppm), there appear to be no adverse effects of sulfur dioxide on plants and vegetation. In fact, in certain instances, there may be a beneficial effect resulting from its presence, since sulfur dioxide converted to sulfate in the soil supplies sulfur essential to plant growth. Ammonium sulfate is a necessary fertilizer for rice production, and for years it was shipped to the Orient from the scrubber on the smelter at Trail, British Columbia under the trademark "Elephant" brand fertilizer. However, at concentrations of 0.025 to 0.040 ppm and above, it appears as if sulfur dioxide could be injurious to vegetation. There is considerable evidence to this effect at Trail, presumably incurred *before* their scrubbers were installed in the thirties.

Corrosion of materials and structures as a result of exposure to gases containing sulfur oxides is also of concern. This is apparent in industrial structures that are subjected to significant concentrations of the oxides. Damage to cloth materials and clothing has also been cited as one of the more subtle aspects of the disintegrating effect of sulfur oxides present in the atmosphere of some dwelling areas. Corrosive damage of this kind can be appreciable in municipalities located in areas where geographical and meteorological conditions are unfavorable to the dispersion of industrial waste gases and combustion products.

Figure 5.3 shows the physiological effect of sulfur dioxide and its oxidation products on humans. The effect is centered on the irritating action produced in the respiratory system. The lowest detectable odor level for sulfur dioxide is about 0.5 ppm, and the tolerable limit for prolonged exposure appears to be a few ppm. It will be noted that the levels mentioned here are above the levels of tolerance for growing vegetation. Hence, if measures are taken to avert damage to plants, and the referenced data are valid, man would be effectively relieved of adverse effects.

It should be obvious, then, that emissions, if completely uncontrolled, could cause and in some instances have caused, damage to people and their environment. Thus the Federal Government, and now the state governments, have stepped in and set up standards and regulations to protect us from ourselves, as growth continues in our population, production, and the subsequent consumption of energy. Perhaps even more troublesome now is the need to shift from oil and gas to coal, a fuel which is considered by many to be environmentally more serious.

There is, however, much controversy surrounding these data which were used to set up present standards. EPRI recently funded a study and concluded that, until further information is available on the health effects of sulfur oxides, it is difficult to make rational decisions for setting standards and developing control strategies. The report also warned for the first time that more attention should be paid to the possible role of SO_2 in the susceptibility of people to cancer.

Recently, the EPA supported work at the Pennsylvania State University on the effects of mortality and air quality in Allegheny County during the period 1968-1972. Particulates were identified as the prime pollutant in about 50,000 deaths associated with diseases of the respiratory system. The correlation with SO_2 levels was not statistically significant. On the other hand, the best fit to their data found SO_2 was directly correlatable with about 4 percent of the deaths from pollution-related diseases (about 2000). Particulates were about seven times more lethal. The bulk of the deaths could be most accurately correlated in terms of the number of days of rainfall.

In addition, the most vocal opponents of scrubbers as a control technology have argued, perhaps with good reason, that even if one accepts the original health data as valid, various agencies are requiring the installation of control technology in areas where ambient data show that the SO_2 levels are generally well below what has been regulated as safe. The cost-benefit problem of adding, say, 15 to 25 percent to everyone's electric bill for such protection (most of the time) on such technology (all of the time) is a major national dilemma.

The answer to whether SO_2 is the real culprit even if sulfur is the element of concern, is not yet well documented. In more recent times, not SO_2, but sulfates have been suspected. Now, evidence indicates that sulfites, possibly sulfites on particulates, may be of most concern and that SO_2 and/or sulfates may be environmentally less of a problem.

For these reasons, coal cleaning looks more and more attractive as a control strategy to meet air pollution regulations, since not only does it get rid of much of the sulfur before it can be released to the air in any form, but it does other things which are definitely beneficial in the generation of steam.

AIR POLLUTION REGULATIONS

Air pollution regulations have had a long, if somewhat irregular history. One of the earliest records of concern is from 14th-century England, where execution was the penalty for failure to comply with a rule against emitting "clouds of smoke and sulfur" into the atmosphere of London. In the U.S., particularly in the 20th century, regulations have been gradually established on a local (city or county) level regulating the emission of particulates (smoke) and odoriferous material such as hydrogen sulfide. However, the past decade has brought much change. Specifically, local governments began to include restrictions against sulfur emissions, and the Federal government established emission and ambient criteria for both sulfur and nitrogen oxides as well as for particulates. Furthermore, the machinery for a national air pollution control network was established.

Ambient criteria set by the Federal government are shown in Figure 5.4. The various states also are required to set local criteria which must be at least as severe as the federal standards. In fact, the current New Mexico ambient standards for the protection of health, shown here also, are equal to the federal secondary standards for the protection of welfare.

Emission limits on various industries have therefore been set to try to avoid exceeding these ambient standards. Federal regulations on power plants apply only to new plants, and currently are fixed at 1.2 lb $SO_2/10^6$ Btu for boilers larger than 280,000 lb steam/hour. The states, in attempting to meet the federal ambient regulations, have been forced to set limits on existing facilities as well.

As an example, the regulations for the State of Pennsylvania are given in Figure 5.5. Pennsylvania is broken down into three areas of concern on the basis of legislation. Designated air basins must have emissions below 0.6 to 1.0 lb $SO_2/10^6$ Btu; plants in other air basins must be below 1.0 to 3.0 lb $SO_2/10^6$ Btu; and plants in relatively pollution-free regions can emit up to 4.0 lb $SO_2/10^6$ Btu. The larger plants have lower allowable emission levels in a given air quality area.

These regions are shown in Figure 5.6, where specified air basins are the most heavily protected designated basins; other air basins indicate the intermediate problem areas, and large boilers in the rest of the state, with the exception of those in Philadelphia and Allegheny County, can emit up to 4 lb of $SO_2/10^6$ Btu. The city of Philadelphia and Allegheny County have set up their own standards, which must be at least as restrictive as those of the state and nation. Homer City, for reference purposes, is located some eighty miles east of Pittsburgh. The novel cleaning process being installed at the Pennsylvania Electric Company plant at Homer City, to be described tomorrow morning, supplies a relatively low-sulfur cleaned coal for the new boiler under construction there to meet federal new source standards. Fortunately, however, it can also discharge a relatively high-sulfur intermediate product coal of about 2 percent sulfur content and still meet Pennsylvania regulations for the two older boilers already operating next to the new plant.

COAL CLEANING TECHNOLOGIES

As it comes from the mine, coal is known as run-of-mine (ROM) coal and consists of a range of sizes from chunks to small particles mixed with some dirt and rocks. In many cases, this ROM coal needs some degree of preparation to meet certain market requirements as to sizes, ash, sulfur, moisture, and heating values. On the other hand, most strip-mined coal is not cleaned as the mining practice can be better controlled to avoid contamination by nonfuel entities. Coal preparation can encompass all activities between the mining of coal and the end use of cleaned coal. These include coal sizing, cleaning, transportation, storage, and refuse disposal.

Size Reduction

Size reduction of the raw coal is accomplished in rotary or roll crushers. The extent of size reduction depends on the type of coal processed and the desired product characteristics. It is a well-known fact that more of the impurities are liberated as the size of coal is reduced. However, because the costs of preparation rise substantially with the amount of fines to be treated, there is an economic optimum in size reduction. On the other hand, as the need for sulfur removal becomes more important, this optimum is shifting toward finer coals.

Coal Cleaning

Washing characteristics of coals vary widely, so that each coal bed must be evaluated individually. In general, it has been found that about half of the pyritic sulfur can be readily removed by washing, without fine grinding, resulting in a 25-percent reduction in sulfur at about an 85-percent yield of coal. Finer grinding almost always increases the separating efficiency. The heating value of the washed coal is also usually somewhat higher, since the ash content is generally lowered. However, there are many exceptions to these general rules.

Many studies have also been carried out on the effect of comminution on subsequent separation schemes based on electrostatic, magnetic, and air-classification technology. In general, results similar to those found by washing have been reported. Dry classification, directly after the grinding step and immediately prior to injecting the coal into the boilers, appears to be one of the more practical approached. However, an inexpensive method to clean the recycle from the classifier has yet to be proven. One of the more promising concepts was electrostatic separation, which Battelle investigated under the support of Bituminous Coal Research, Inc., some 15 years ago. A small pilot unit was developed to electrostatically remove the pyrite from finely ground coal. We feel it may be a more attractive approach than many of the so-called advanced processes currently in vogue. Many of the newer techniques to clean coal will be described tomorrow. However, today we are going to mainly review what is commercially used around the world.

Coal cleaning now being practiced may be classied into four levels of preparation:

Level 1—Breaking for top size control only, with limited removal of coarse refuse and trash

Level 2—Coarse beneficiation through washing of plus 3/8-inch material only after crushing to a top size in the range of 1-1/4 to 5 inches

Level 3—Deliberate beneficiation through washing of plus 28 mesh material after crushing to a top size in the range of 1-1/4 to 5 inches

Level 4—Full beneficiation through washing of minus 28 mesh material in addition to level 3.

Preparation practice for deep-mined steam coal lies between levels 2 and 3, while metallurgical coals are usually beneficiated through level 3. Current costs and yields, with ROM coal at about $15/ton, for these levels of treatment have been estimated to be about as shown in Figure 5.7. Actual costs can vary widely, are very site specific, and obviously depend upon the nature of the coal and the care with which it is mined.

Separation of ash and pyrite from the coal is accomplished with a variety of devices for three individual size groupings. The types of processes and equipment used over the years in coal cleaning are summarized in Figure 5.8. In coarse coal circuits, the coal is cleaned with one or a combination of gravity separation equipment such as jigs or heavy-medium vessels. The intermediate size coals are usually cleaned with concentration tables or heavy-medium cyclones. In cleaning of fine size coal, froth flotation or hydrocyclones are often employed.

The commercial practice of coal cleaning is currently limited to the gravity methods together with minor application of the froth flotation methods. As shown in Figure 5.8, jigging still handles the largest portion of coal cleaning. However, dense-medium processes and concentrating tables are becoming more popular, and froth flotation is starting to play an important role.

Water Removal

Following any wet separation process, the product coal requires dewatering or complete drying, depending on the ultimate use and transportation systems being utilized. For coarse size coal, dewatering can be accomplished by natural drainage using dewatering screens or bucket elevators. Dewatering of intermediate size coal is accomplished with sieve bends and centrifuges. Some thermal drying may be required to reduce the moisture content of the product. With fine size coal, dewatering requires not only more complicated mechanical techniques, such as centrifugation or vacuum filtration, but also thermal drying to obtain an acceptable moisture content.

COAL PREPARATION AROUND THE WORLD

We now would like to take you on a photographic tour around the world to review coal technology currently in use. We will start out in the western United States and end up in the Ukraine.

United States

At Colstrip, Montana, the Montana Power Company operates two 360-MW boilers operating on Rosebud seam coal. The facility is shown in Figure 5.9. Frankly, we do not understand how some people always object to the location of power plants. That is a beautiful setting for a relatively clean operation. Much prettier than some sections of this city, for instance, and as impressive as the Washington Monument, certainly. Figure 5.10C shows the draglines in the distance, scrapping off the overburden from the nearby strip mines, and Figure 5.11 shows the power shovels digging into the Rosebud stream after the overburden has been cleared off. Very clean separation of coal and nonfuel values is obtained by simply using care in the mining operation. Now what is interesting is that the Colstrip power plant operation has scrubbers on the flue gas to reduce emissions to meet NSPS, since although the Rosebud seam contains only 0.6 percent sulfur, it also has a low heating value of only 8,500 Btu/lb. What is even more interesting is the fact that this same coal is transported east almost 1000 miles to the Sherburne Station of Northern States Power Company. There, its combustion products are also scrubbed. This example of western coal, which is scrubbed in the west and in the east, and still presumably represents the lowest cost energy system to supply electricity at these two locations, indicates the technical complexity of the sulfur control issue. Ironically, the McCoy seam, which is another seam located about 12 feet below the Rosebud seam, contains 1.5 percent sulfur. After mining the Rosebud seam, it is simply covered back up because of its "high" sulfur content.

Now let us shift to Maple Meadow, West Virginia. There is a plant there that belongs to Cannelton Industries, Inc., which in turn is owned by Algoma Steel Corporation, Inc., the second largest steel producer in Canada. All Maple Meadow coal goes for Algoma's plant at Sault Ste. Marie, Ontario. Figure 5.12 shows the coal crusher at the washing plant. The storage silo for the crushed coal is shown in Figure 5.13. A cyclone separator to classify the overflow from the desliming screens is shown in Figure 5.14. A sieve bend, used to screen fine particles rapidly, is shown in Figure 5.15. A right angle change in direction is forced on the wet shear, thereby gaining the benefit of centrifugal action to maintain high throughput rates. A froth flotation cell is shown in Figure 5.16. Lift blades assist in causing the froth, which carries suspended particles, to overflow into collecting vessels. These particles must be filtered to remove water in an apparatus containing filter screens like those shown in Figure 5.17. Finally, the underflow from the froth flotation cells is sent to the classifier shown in Figure 5.18. The black water is returned to the plant and the fines are rejected to a waste disposal area.

Western Europe

Ireland. In Ireland, electricity is generated almost entirely by the combustion of peat, which can consist of up to 95 percent water. Peat is also the principal fuel for Irish homes and businesses. Obviously, it must be dried to generate any significant net useful heat. Furthermore, the heat for drying must be essentially free. Solar heat must therefore be utilized. However, peat is usually formed in regions of cool damp weather, where net rainfall may exceed net evaporation, presenting problems in the effective use of solar heat for drying.

A relatively new system designed to solve this dilemma is shown in Figure 5.19. Leveling machines first excavate a thin layer from the surface of milled peat fields. Large macerating machines then form the peat into small, dense sods which have a surface skin resistant to rewetting. The formed sods are then laid across the field to dry. This equipment is now extensively employed to supplement milled peat production during bad weather seasons.

Each machine weighs 23 tons but has a ground bearing pressure of only 1.6 pounds per square inch. There are two engines mounted on each machine: one to drive tracks, elevator, conveyor, and spreader; the second to drive the macerator. The machine picks up peat over a width of 45 feet, and the forward speed can be varied from 150 to 300 yards per hour. Each machine can spread 8 acres in a 10-hour period. Battelle helped design this machine under the support of the Irish government.

West Germany. The largest coal mine in the world is the Fortuna-Garsdorf mine near Cologne, West Germany. The 1972 production was 42 million tons/year, equivalent to about 1/10 of the U.S. needs by 1985 to meet President Carter's goal. As shown in the map in Figure 5.20, the area covers some 970 square miles and contains 600 billion tons of 3,400 Btu/lb lignite or "brown coal". Seam thickness average about 160 feet. The mine depth is about 600 ft with plans to dig to 1000 ft. Extensive work was necessary to prevent water inflow into the mine from the adjacent Erft River. In the initial development of the mine, some 1.2 billion cubic yards of overburden had to be transported out of the pit. Over 1800 deep wells, each supplied by 4000 gpm pumps, prevent significant inflow of water. An 11-mile canal to the Rhine River takes the output from this massive drainage system. An equivalent operation in the U.S. to meet our new coal needs would be to move the city of Baltimore, for example, over to Virginia to get at the coal reserves in Maryland.

The region in red on the map is active mine area, the region in orange is area being restored to productive use either by slurry or belt conveyor of wastes to previously mined regions, and the area in brown is reclaimed forest land. The costs of reclamation were estimated to be $16,000 per acre, obviously a tolerable cost only in the densely populated Rhine. We would now like to show some scenes of the fantastic equipment used to get the coal to the boilers, the waste to the reclamation areas, and the results of the extensive reclamation efforts.

Figure 5.21 is a view looking down into one of the mine areas. It tends to enclose its own peculiar weather patterns, and in Pennsylvania, this might be called a designated air basin. A wheeled bucket excavation is shown in Figure 5.22. These devices are used to continuously "mill" the brown coal into the transportation system set up for the mine. Some of the belts used to move the products are displayed in Figure 5.23. Slurried waste is deposited in worked-out areas of the mine, as shown in Figure 5.24, and allowed to dry, as depicted in Figure 5.25. An experimental farm, shown in Figure 5.26, is located on top of this reclaimed work. New irrigation canals like those in Figure 5.27 must be dug in this reclaimed land if productive use is to be reestablished. A resort lake on restored land is shown in Figure 5.28. Figure 5.29 is a photograph of sugar beets being harvested on reclaimed land, a new town shown in Figure 5.30 has been constructed in a restored area for those who must be housed in the future as the mining operation proceeds into other inhabited areas.

Next, we might examine what Nordwestdeutsche Kraftwerke (NWK) is doing for SO_2 control at their new 710 MW unit at Wilhelmshaven. A photograph of the unit is shown in Figure 5.31. Coal will be purchased from South Africa and Poland. About 20 percent of the flue gas will be scrubbed. South African coal will contain 1.3 to 1.4 percent sulfur, but it is very difficult to wash, as the ash in South African coal is very uniformly distributed. This is one reason the South Africans chose the Fischer-Tropsch process rather than Bergius process for the production of synthetic fuel. The Polish coals will contain 0.8 to 0.9 percent sulfur and will have already been washed in Poland.

Eastern Europe and Russia

Poland. Almost the entire output of bituminous coal in Poland, some 150 million tons per year, is washed to achieve partial desulfurization. The pyrite content of Polish coal is relatively high, in the range of 70-96 percent of total sulfur. Run-of-mine coal averages perhaps 2 percent sulfur. Sulfur concentration in coarse concentrate therefore does not exceed about 1 percent, although some untreated smaller sizes are used in power stations and may average significantly higher in sulfur content.

Soviet Union. All Soviet coking coals are washed, while only about one-third of the coals used for steam generation are so treated. Generally, steam coal is washed only down to 1/2 to 1/4 inch, although in some cases the finer fractions are washed.

The Komsomol Central Coal Preparation Plant in the Ukranian District of the Soviet Union, is shown in Figure 5.32. The plant went on line in 1968 and undoubtedly represents one of the most modern Russian plants. It may or may not be typical of current Russian practice. The plant was designed and constructed to process hydraulically mined and hydraulically transported coal from a nearby mine. It has a capacity of 500 tons per hour of metallurgical grade coal.

The coal-cleaning circuitry for this plant includes jigs and flotation cells. The coarse coal is dewatered on screens and in centrifuges; the fine coal from the flotation circuit is dewatered via a thickener and disc filter circuit. The filter cake is dried in a rotary drum dryer. All of the principal unit operations are mechanized and automated.

As shown in Figure 5.33, the Russians also have not completely solved the disposal problems of refuse from preparation plants. As may be noted in this view from the road near the plant shown in the previous figure, a glob pile of refuse from the preparation plant is the most prominent feature to the right on the horizon, several kilometers from the plant.

INSTITUTIONAL CONSTRAINTS

Institutional constraints facing the coal cleaning industry include the lengthening list of environmental limitations, the developing regulatory climate, the rising expectations of workers, the growing recognition of the importance of reclamation, and finally, the unsettling investment uncertainties involved.

Environmental Impacts

Although the coal coming from a coal cleaning plant is by definition "cleaner" than the feed coal, one should not necessarily get the impression that this is a "clean" operation. If you find power plants unsightly, you may be shocked by what takes place at many mines, especially smaller ones. A bad example is shown in Figure 5.34. At current production levels, about 100 million tons of *extra* solid wastes would accumulate at American underground mines each year, *if* it were all cleaned. As you are well aware, the waste material produced by strip mines is an enormous problem in itself, but at least it usually resembles the natural earth in appearance.

Normally the fine refuse from preparation plants is a slurry and is now usually piped to a settling pond. Formerly the slurry ("black water") was often simply discharged into the nearest stream. The water, of course, can be highly acidic in nature. The coarse refuse was generally piled at the closest location adjacent to the cleaning plant. Pyritic waste is readily oxidized, and spontaneous combustion was often induced. Once started, refuse fires are extremely difficult to extinguish. They have been known to smolder for decades. There are probably some 300 burning waste dumps in Appalachia today.

Coal refuse piles almost invariably resist the establishment of any kind of natural vegetation. Severe rain and wind erosion occur. Slope instability and landslides are the inevitable results. The consequences can be tragic. Collapse of a rain-soaked refuse bank in the Welsh coal-mining village of Aberfan in 1966 took 144 lives, 116 of them school children.

Regulatory Aspects

After passage of various state and Federal water-pollution legislation, the slurry from preparation plants began to be discharged into impoundments constructed of the coarse aggregate. As the water seeped through this material, the suspended fine coal particles were filtered out, and the water entering the stream was at least clear. Failure of an impoundment of this type in West Virginia in February of 1972 released about 21 million cubic feet of water, causing the Buffalo Creek disaster. In a matter of a few minutes 125 people were killed, and the homes of more than 4,000 others were totally destroyed. The original regulations on impoundment had backfired.

The Aberfan and Buffalo Creek disasters and the rising influence of environmentalists stimulated much further legislation in attempting to correct these tragedies. Unfortunately there is currently much confusion about application of, and jurisdiction over, these regulations. Most recently, air emission regulations on particulates from cleaning plants have been promulgated.

Human Resources

Workers at coal mines and plants are like the rest of us. They want higher standards of living, better working conditions, and a pleasant community in which to raise their families. They need to be involved and recognized for their efforts. We should so do it.

Reclamation Aspects

Reclamation efforts obviously must be carried out but these may be expensive operations. Shown in Figure 5.35 are Herefords grazing on restored strip-mine land in Ohio, which belongs to the Consolidation Coal Company. However, as in the case of environmental control, there is no clear point where one decides to stop and say "we have done enough". The $16,000 for restoration per acre at the Fortuna mine clearly is too high for most of the U.S. But what is enough?

Investment Considerations

A major constricting item facing the coal-cleaning industry, like the energy industry in general, is investment problems.

One consideration is uncertainty. What will the regulations be in the future? If one installs a cleaning plant whose key to economic viability is the burning of a middling fraction of intermediate sulfur coal, industry must be assured that regulations will not become more strict in the future, and that they can burn this product for the next 30 years or so. In a similar vein, they also need to be assured that regulations will not be relaxed, resulting in a waste of investment capital and economic losses in technology not really needed to protect health or welfare.

Another consideration concerns the ownership of the cleaning plant. Presumably, a utility would prefer not to own the plant—it could thus pass future variations in cleaning costs directly on to its customers as a fuel cost. On the other hand, there are numerous small mines where installation of a small cleaning plant would be prohibitively expensive.

ECONOMIC TRADE OFFS

At the start of the Battelle Energy Program, which was launched in December of 1973, Battelle reviewed the economics of various coal technologies suitable for sulfur removal. The most cost effective method proposed by Battelle for removing pyritic sulfur from coal was to use preferential air oxidation at 340 to 450 C in a fluidized bed. The only effort Battelle has announced so far, however, is hydrothermal leaching. It has the potential to remove organic sulfur, and in addition opens up vast new technical areas based on reacting coal with water, including gasification, liquefaction, pipeline processing, and chemical production.

The costs for desulfurizing coal have been exhaustively examined and the results are shown in Figure 5.36. This graph has been generalized so that the costs of all chemical-cleaning processes so far publicly announced by all organizations throughout the world fall within the 15 to 25 dollars/ton price range. The cost of coal conversion technologies, like gasification and liquefaction generally run considerably higher, i.e., in the range of $25 to $50 per ton of mined coal.

In short, chemical cleaning of coal appears to be best suited for nonbaseload power-plant boilers or for industrial size boilers, and for coal having a low enough organic sulfur content to allow SO_2-emission regulations to be met.

Our staff has estimated the market potential for chemically cleaned coal for combustion purposes at a price of $40 to $50 per ton to be about 41 million tons/year in the mid-80's for electricity generation, and about 86 million tons/year for industrial markets. This represents a $6-billion/year market potential. The problem, of course, is the distribution network which must be set up to supply those smaller boilers. The market and technologies are extremely sensitive to environmental regulations, which can rapidly change, and to the degree of sulfur removal possible on each different type of coal seam. So far this market potential has not looked sufficiently promising to be translated into an active commercial activity.

Obviously, if physical cleaning will produce a product which will meet environmental regulations, it should be employed. There is no other technology developed today that can compete on a cost basis. As will be shown tomorrow, it also should be considered as a technology in combination with others.

THE ENVIRONMENT FOR CLEANING

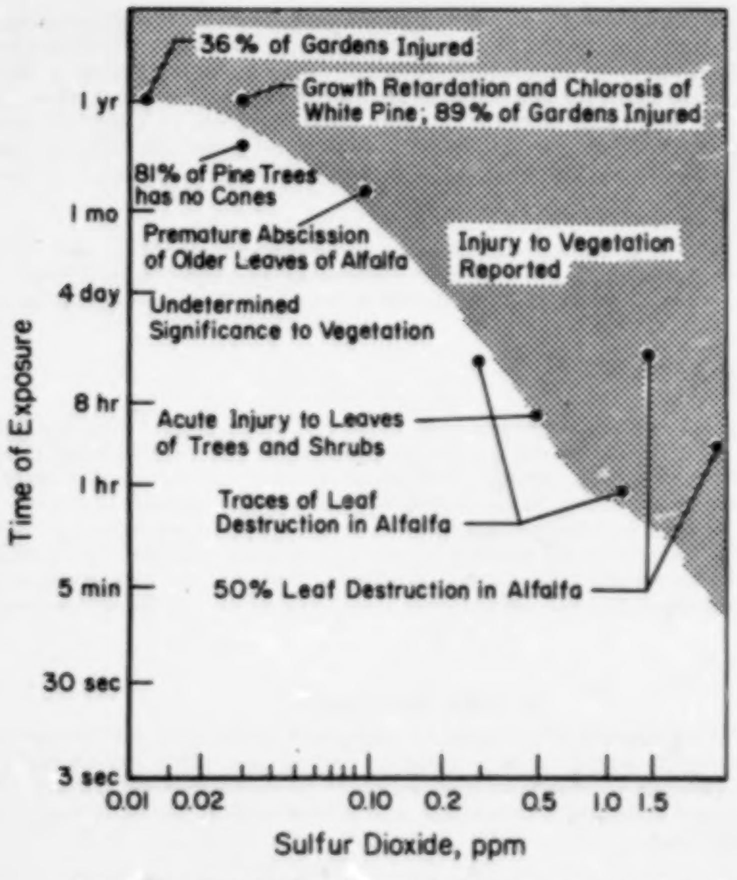
The basic question to be answered not only in the control of sulfur during the combustion of coal, but in control of all pollutants involving control technology in general, is how much are we willing to pay for the improved quality of our environment? We can reduce man-made pollution levels to zero. If we can create our own environment on the moon, we certainly have the technical competence to do it on earth. However, the costs and energy requirements for a zero pollutant life on earth will be essentially infinite. Somewhere before we get to absolute environmental control, there must be an optimum cost-benefit level which has yet to be satisfactorily defined by society. Until we can define such a cost-benefit goal, we will continue to drift without firm objectives which can be understood by all our citizens.

ACKNOWLEDGMENTS

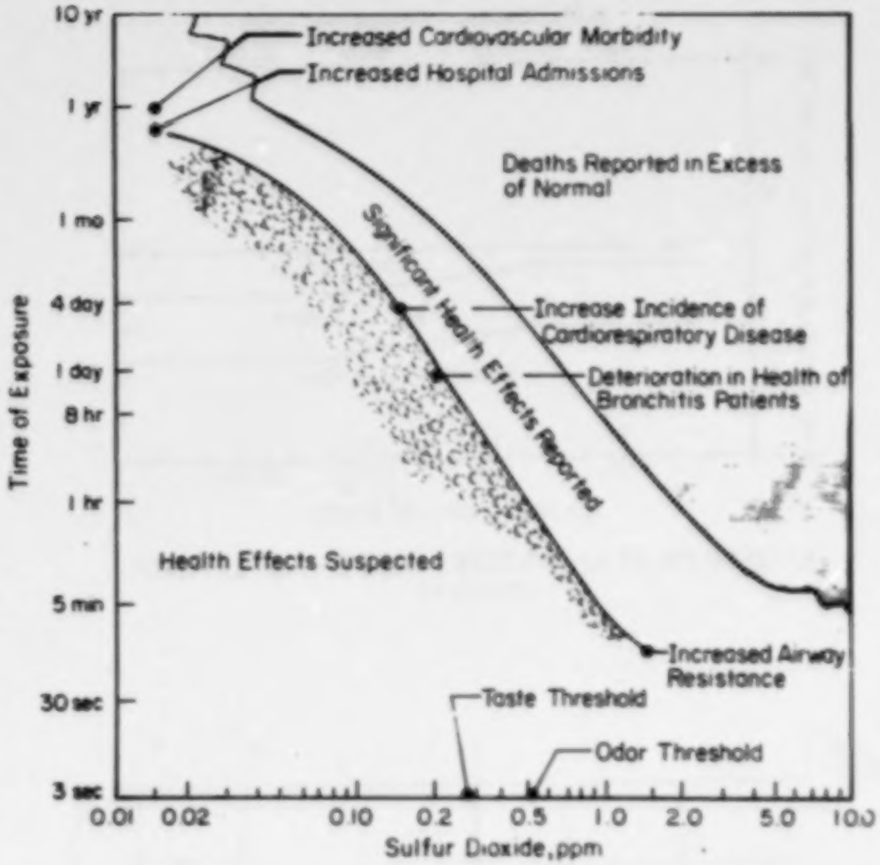
We would like to acknowledge the use of photographic material supplied by Messrs. Richard J. Anderson and John J. Breslin on the mining operations in Montana, Ohio and Germany, to Messrs. Harry S. Rosenberg and Mazen Y. Anastas for the figures on the preparation plant in West Virginia, and Messrs. James J. Grimm and Howard C. Davis for the information on peat mining activities in Ireland. All are members of Battelle's staff.

Moisture and Ash Free:	
Carbon	69–94
Oxygen	2.2–24.
Hydrogen	2.2–6.0
Sulfur	0.5–6.3
Nitrogen	0.8–2.5
As Received:	
Mositure	1–43
Ash	3–30

COMPOSITION OF U.S. COALS USED FOR POWER PRODUCTION
FIGURE 5.1



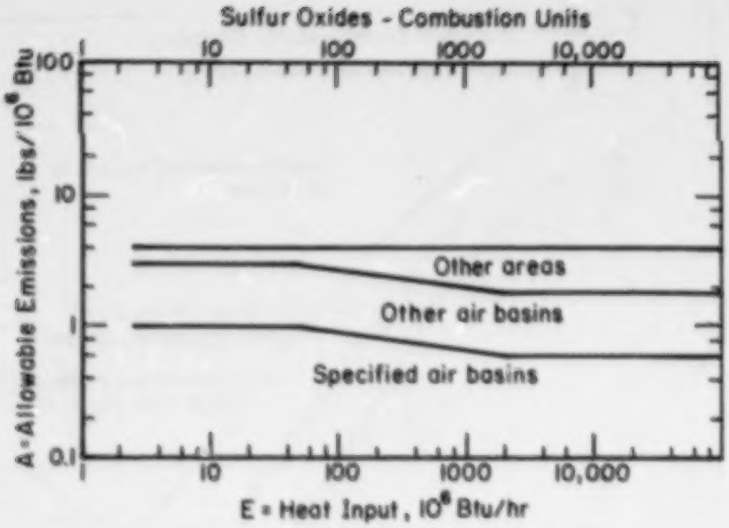
EFFECTS OF SULFUR OXIDES ON VEGETATION
FIGURE 5.2



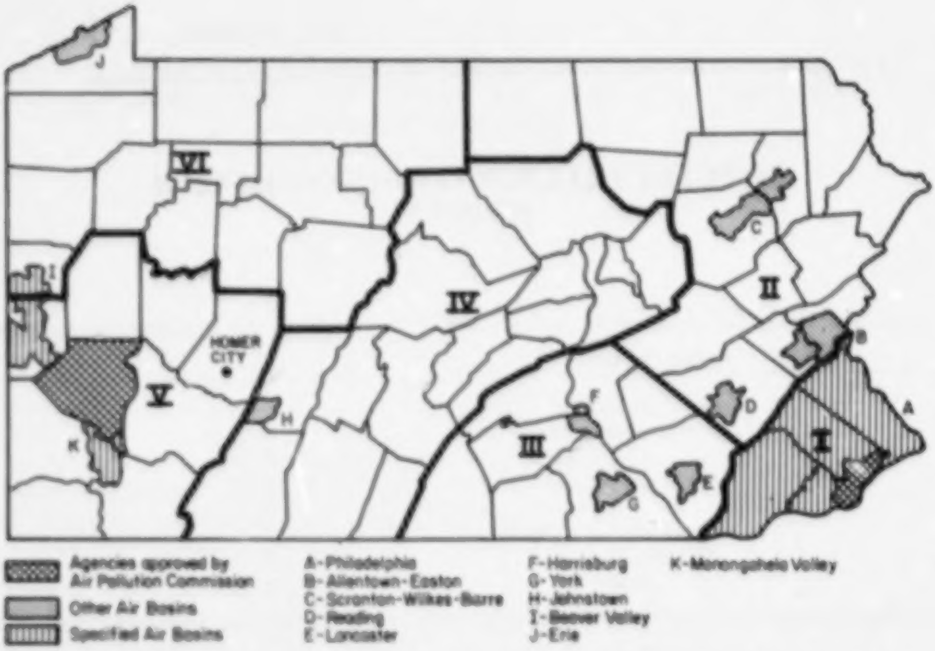
EFFECTS OF SULFUR OXIDES ON HEALTH
FIGURE 5.3

Sulfur Dioxide	
Federal Standards	
Primary-Annual	0.03
24-hr. max.	0.14
Secondary-3 hr max	0.50
New Mexico Standards	
Present-Annual	0.02
24-hr.	0.10

AMBIENT AIR QUALITY STANDARDS (PPM)
FIGURE 5.4



EMISSION STANDARDS FOR PENNSYLVANIA
FIGURE 5.5


J
VI
I
IV
II
C
B
HOMER CITY
V
H
F
D
A
III
I
K
G
E
Agencies approved by Air Pollution Commission
Other Air Basins
Specified Air Basins
A-Philadelphia
B-Allentown-Easton
C-Scranton-Wilkes-Barre
D-Reading
E-Lancaster
F-Harrisburg
G-York
H-Johnstown
I-Beaver Valley
J-Erie
K-Monongahela Valley

PENNSYLVANIA'S AIR POLLUTION CONTROL REGIONS
FIGURE 5.6

Level of Preparation	Btu Yield	Costs, $/ton of Cleaned Coal
1	99%	1.20
2	95%	5.50
3	90%	8.90
4	87%	11.80

TYPICAL COSTS AND YIELDS FOR COAL CLEANING

FIGURE 5.7

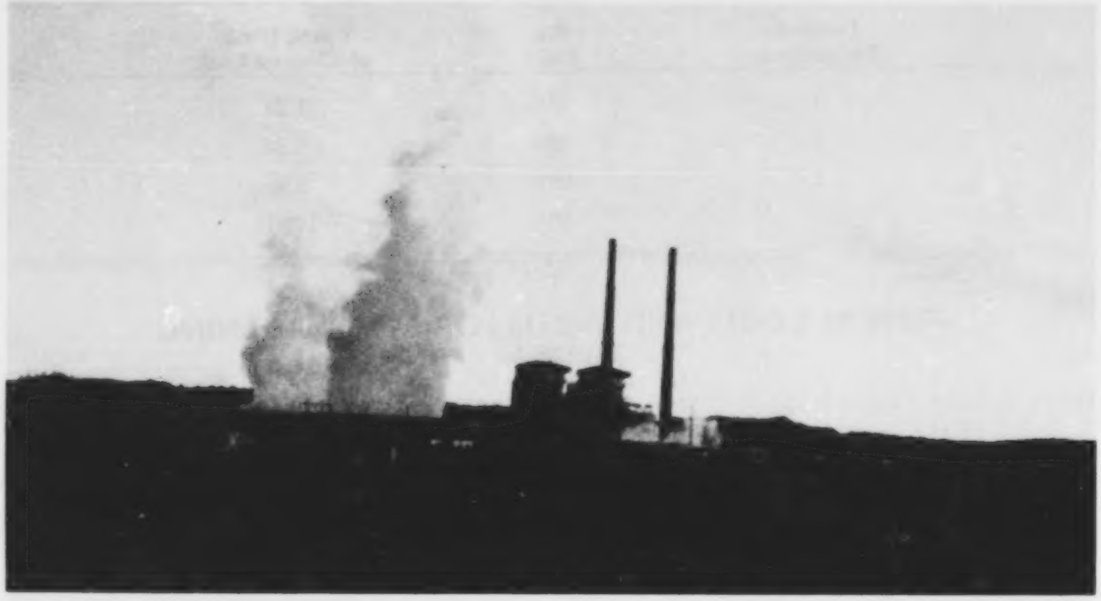
Source: Phillips, P. J and DeRiengo, P. P., "Fixing Up Coal: What It Can Cost", Public Utilities Fortnightly (April 14, 1977) pp 29–33.

Washer Type	1942	1952	1962	1972
Jigs	47.0	142.8	50.2	43.6
Dense-medium processes	8.8	13.8	25.3	31.4
Concentrating tables	2.2	1.6	11.7	13.7
Flotation	—	—	1.5	4.4
Pneumatic	14.2	8.2	6.9	4.0
Other	20.5	13.7	4.3	2.9

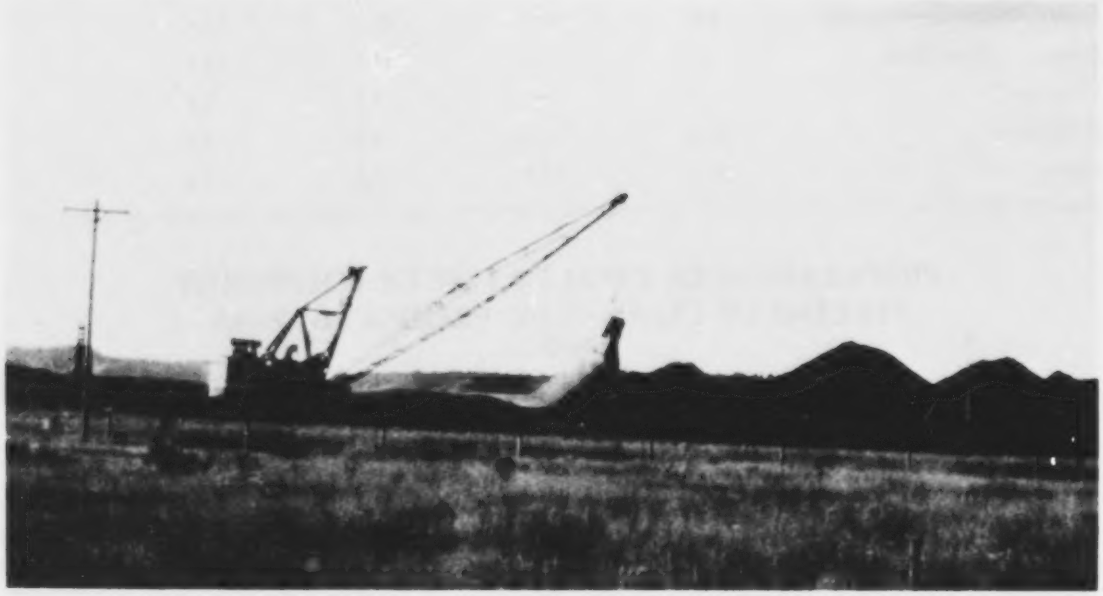
PREPARATION OF COAL BY TYPE OF EQUIPMENT PERCENT OF CLEAN COAL PRODUCED, YEAR

FIGURE 5.8

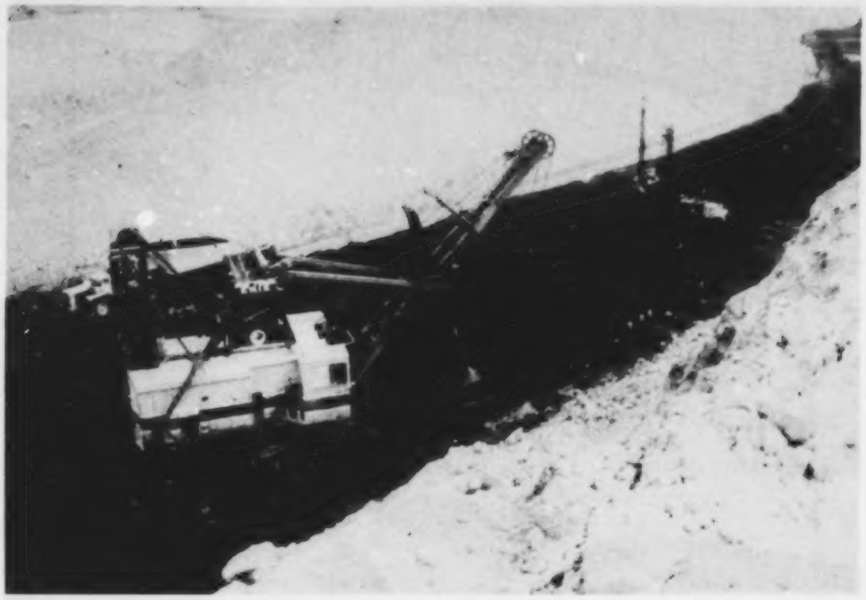
Source: Deurbrouck, S. W. and Jacobsen, P. S., "Coal Cleaning—State of the Art", Paper presented at the Coal and Environmental Technical Conference and Experiment Exposition, Louisville, Kentucky, Oct. 22–24, 1974.



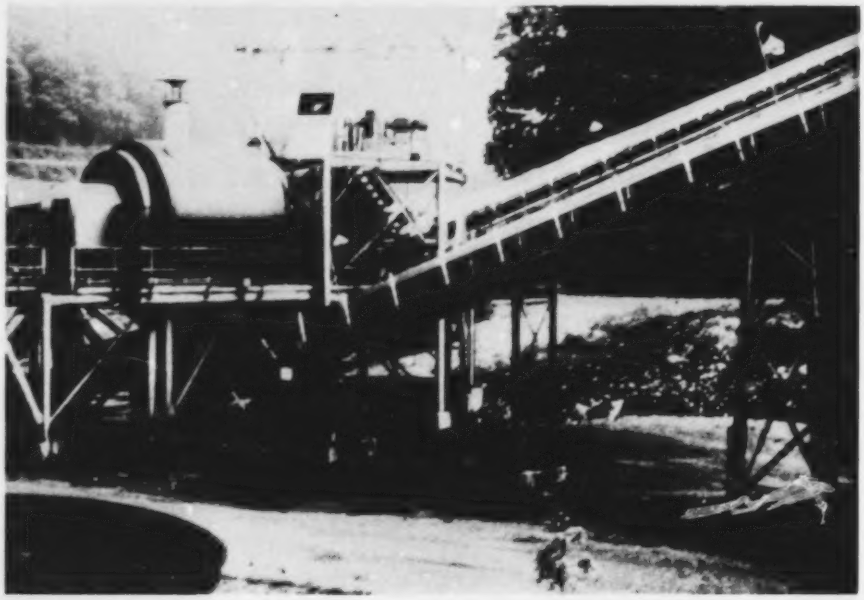
MONTANA POWER'S COLSTRIP STATION
FIGURE 5.9



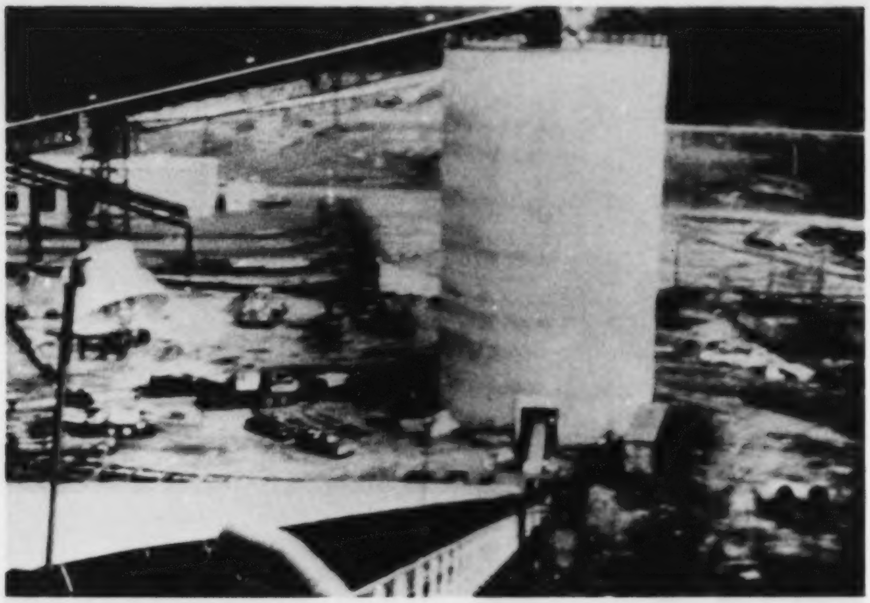
DRAGLINES IN OPERATION AT COLSTRIP
FIGURE 5.10



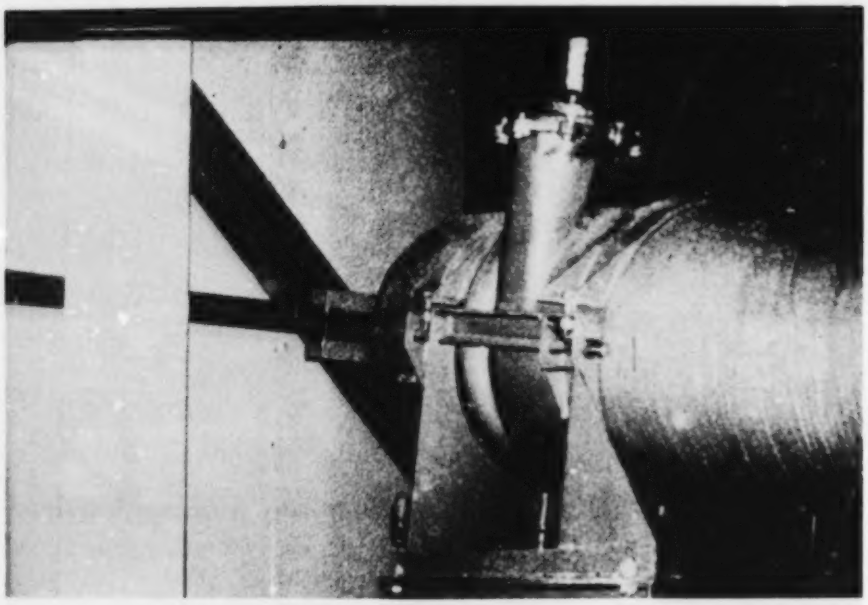
MINING THE EXPOSED SEAM
FIGURE 5.11



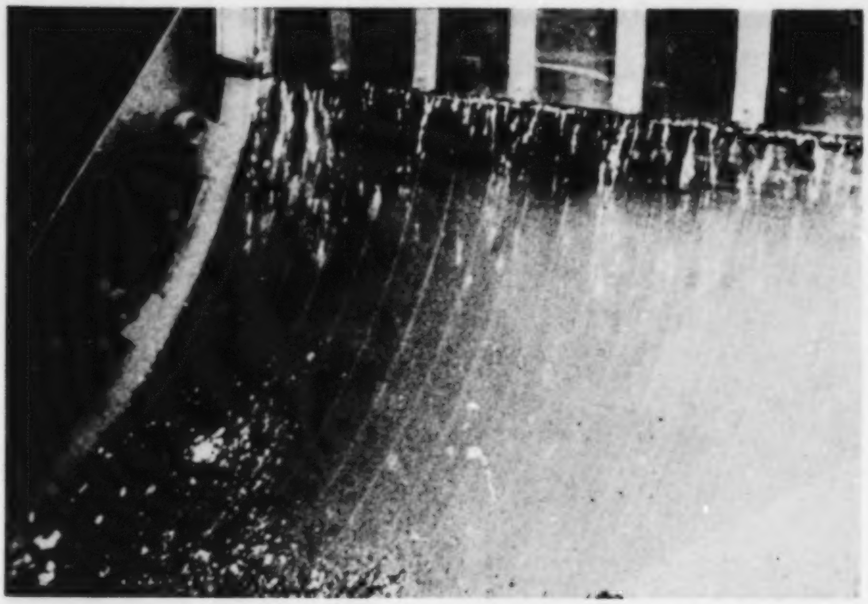
COAL CRUSHER AT MAPLE MEADOW
FIGURE 5.12



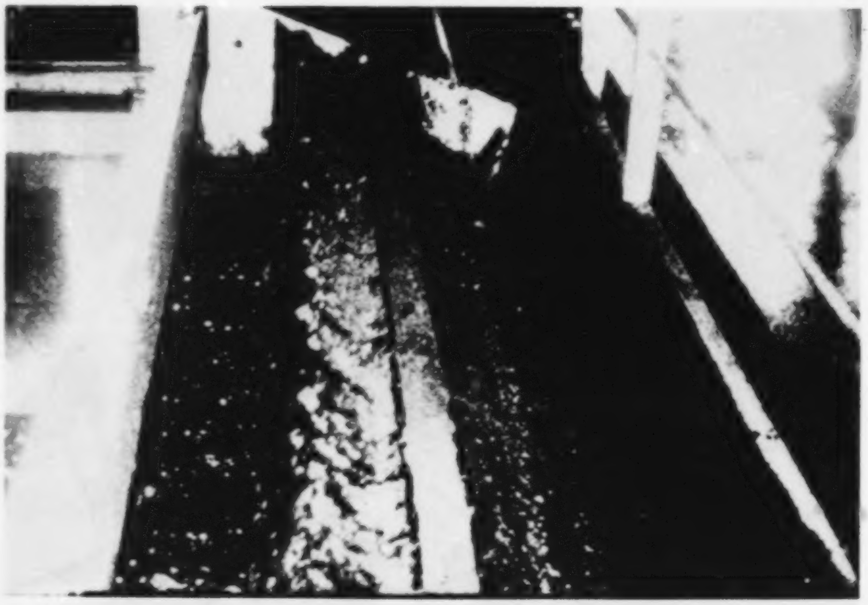
CRUSHED COAL STORAGE SILO
FIGURE 5.13



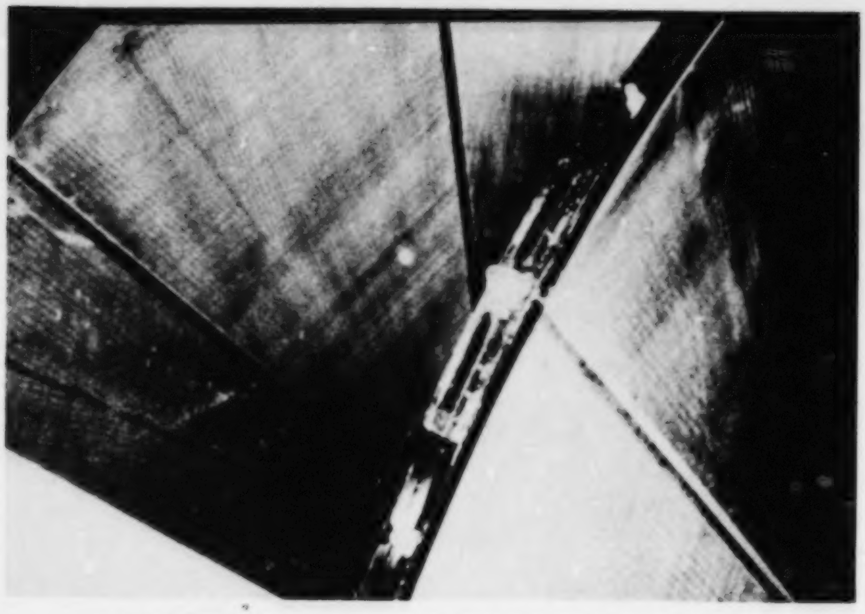
CYCLONE SEPARATOR IN PRIMARY CIRCUIT
FIGURE 5.14



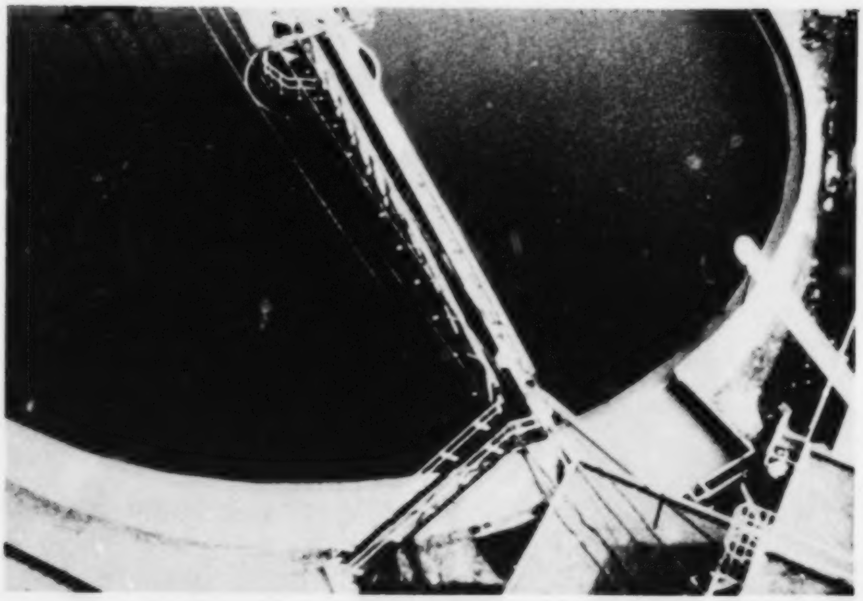
SIEVE BEND FOR DEWATERING INTERMEDIATES
FIGURE 5.15



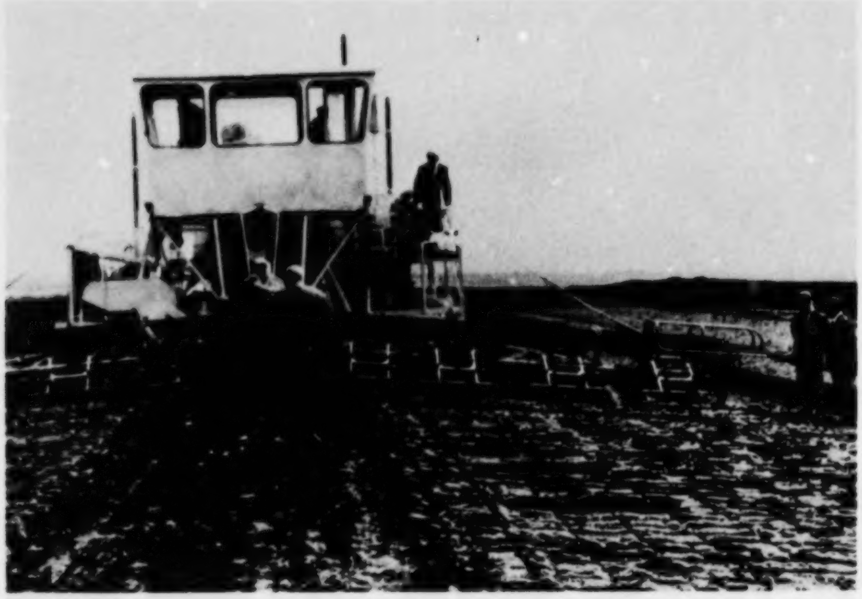
FROTH FLOTATION CELL FOR FINE-COAL
FIGURE 5.16



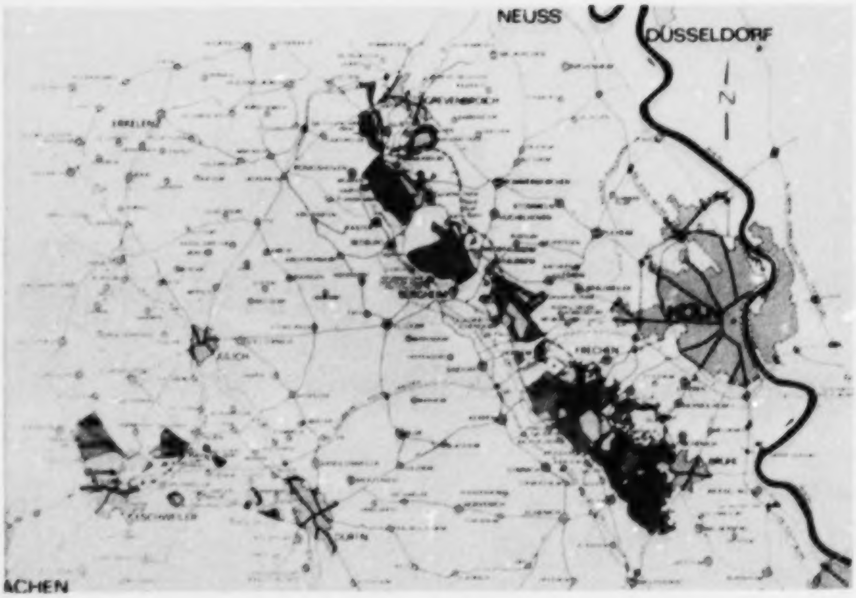
FILTER PLATES FOR DEWATERING FINES
FIGURE 5.17



CLARIFIER FOR FLOTATION CELL UNDERFLOW
FIGURE 5.18

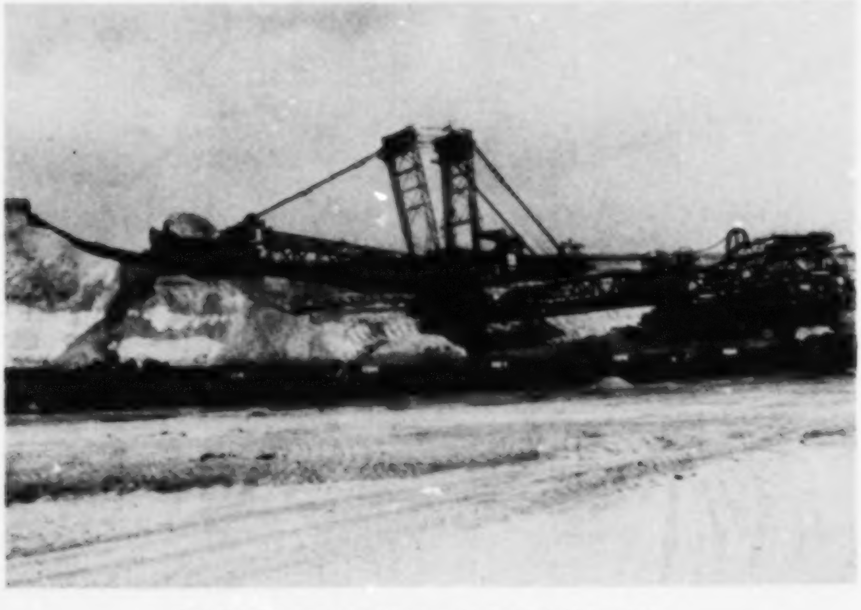


PEAT MINING MACHINE IN IRELAND
FIGURE 5.19

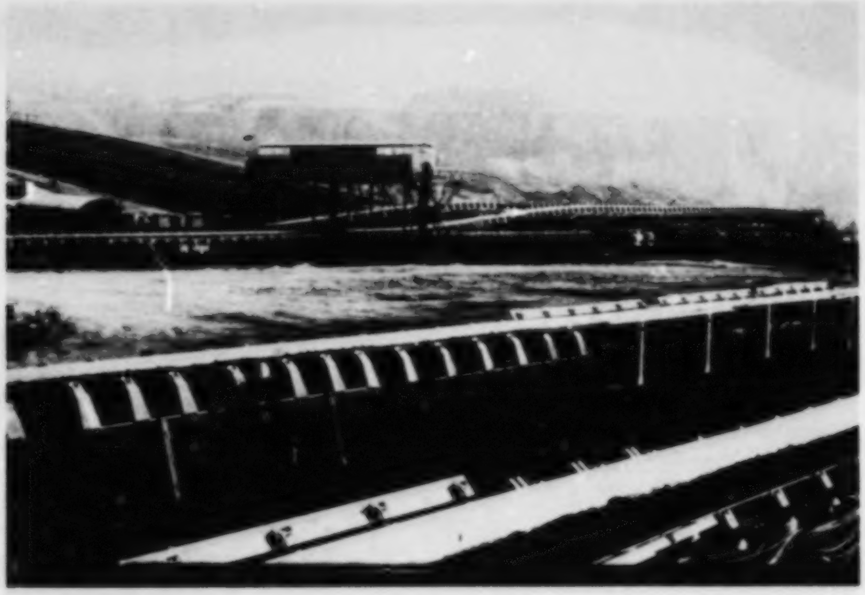

NEUSS
DÜSSELDORF
N
ACHEN

BROWN COAL OPERATIONS NEAR COLOGNE
FIGURE 5.20

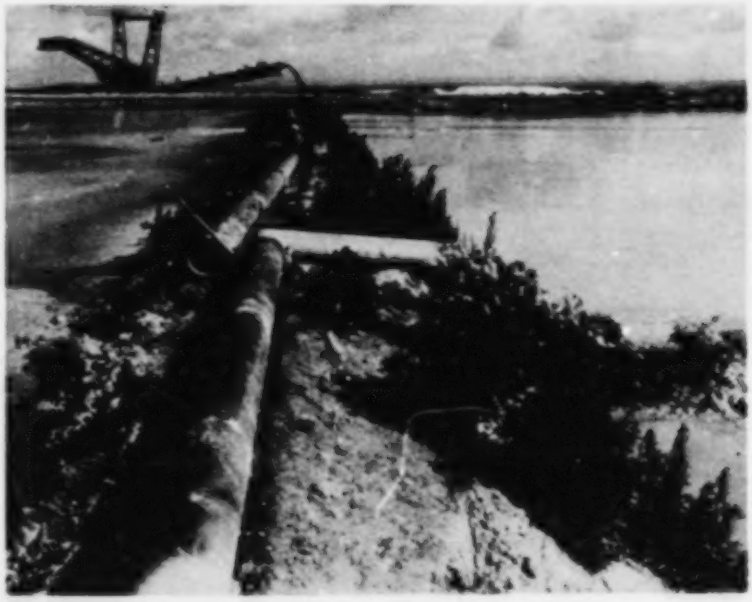
VIEW OF OPEN PIT MINE
FIGURE 5.21



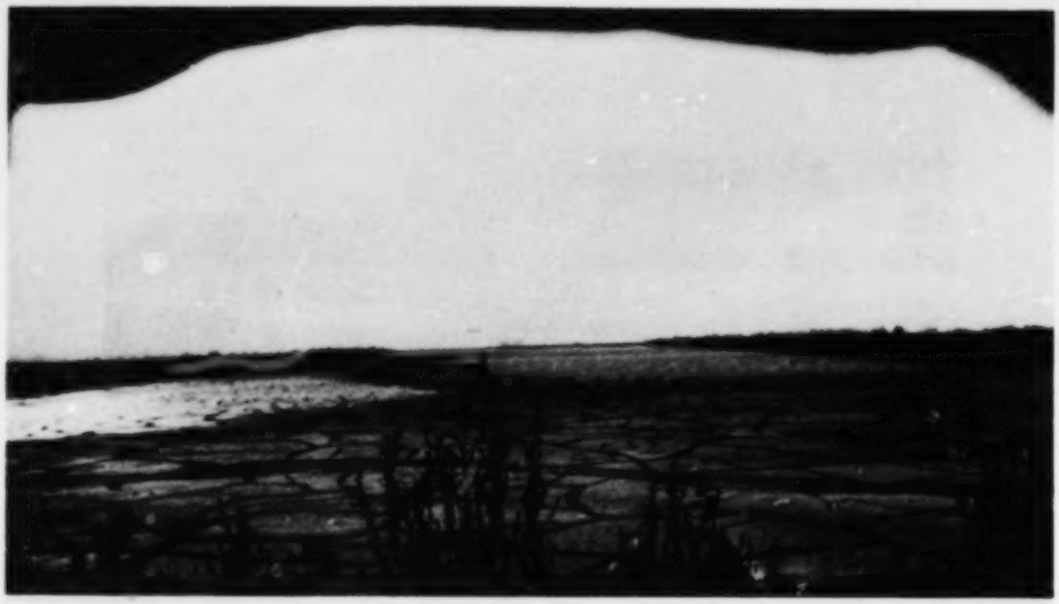
WHEELED BUCKET EXCAVATOR
FIGURE 5.22



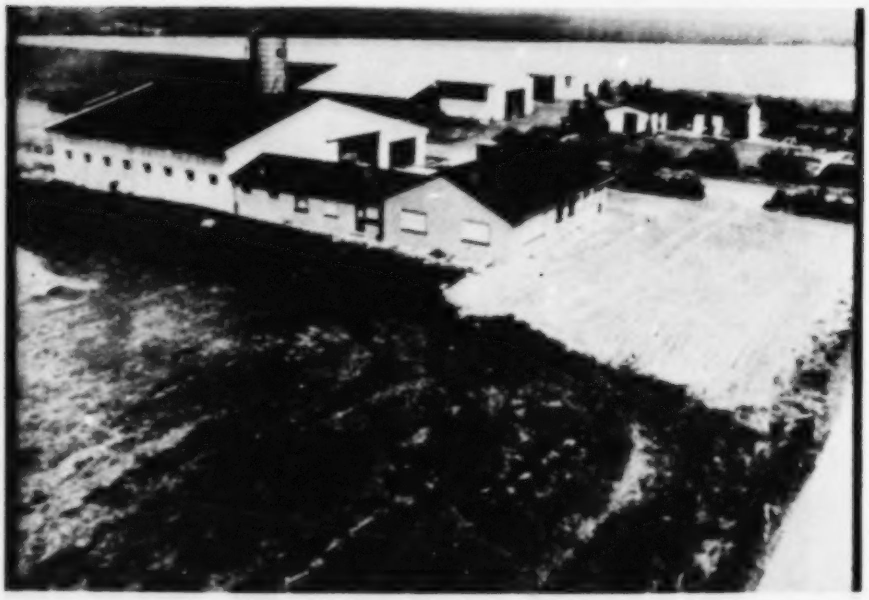
BELT TRANSPORTATION SYSTEM FOR COAL
FIGURE 5.23



SLURRY TRANSPORTATION SYSTEM FOR WASTES
FIGURE 5.24



DRIER SLURRY PONDS
FIGURE 5.25



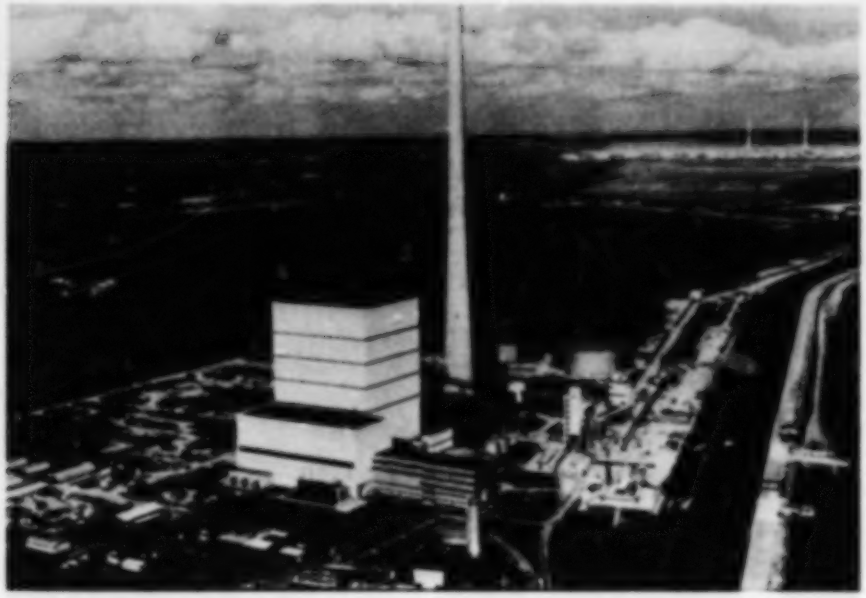
EXPERIMENTAL FARM ON RECLAIMED LAND
FIGURE 5.26

IRRIGATION CANALS ON RECLAIMED LAND
FIGURE 5.27

RESORT LAKE ON RECLAIMED LAND
FIGURE 5.28

HARVESTING SUGAR BEETS
FIGURE 5.29

NEW TOWN FOR DISPLACED HOMEOWNERS
FIGURE 5.30



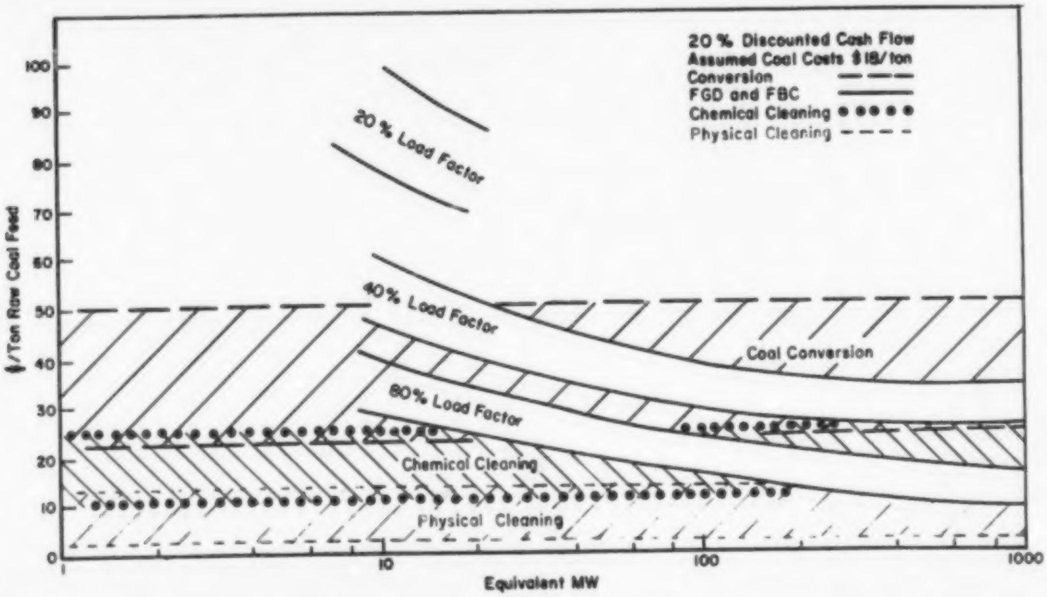
NEW NWK PLANT AT WILHELMSHAVEN
FIGURE 5.31

KOMSOMOL CENTRAL COAL PREPARATION PLANT
FIGURE 5.32

RUSSIAN GOB PILE
FIGURE 5.33

ENVIRONMENTAL IMPACT OF A CONTOUR MINE
FIGURE 5.34

HEREFORDS GRAZING ON RESTORED LAND
FIGURE 5.35



COSTS FOR SULFUR CONTROL
FIGURE 5.36

OPENING REMARKS, SECOND DAY

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Good morning. Yesterday's speakers gave us an interesting perspective of the problems—the opportunities—of coal utilization. They gave us some sense of the role of coal cleaning, which we are going to explore further today. I would like to just comment on yesterday and today from a different perspective.

Yesterday we dealt largely with problems of economics, financing, and cost of operation. We dealt with manpower, resources, and limitations. We dealt with the energy coal demand problems, coal demand expectations, and the environmental trade-offs. We dealt rather emotionally with the regulatory morass and the uncertainties that companies are faced with. We dealt somewhat with the coal industry infrastructure. We also touched very briefly on the technological issues, and we will delve into some of those more deeply today.

I am a technologist, frankly a very frustrated technologist. The reason for the frustration is the inability of technology by itself to extricate us from the problems that we face today. I was at a luncheon a few weeks ago and a question was posed in a discussion over coffee, "What profession will do the most to solve the energy problem"? I thought about that for a while and I said, "Well, concerning all the problems with the lawyers (I hope there aren't too many lawyers here), the legal profession". I was kind of amused—Steve Friedman from ERDA (he gave me permission to quote him here) was sitting next to me and he responded, "Psychologists, and I hope, by God, not psychiatrists".

As an engineer, I think of the options before us in terms of trade-offs—trad-eoffs between energy demands, environment, and, on another plane, employment versus inflation. And there is a whole variety of other trade-offs that we could consider. However, the problems before us have reached the point where they touch every citizen in the country. Consequently, whatever solutions we obtain must arise from a general consensus resulting from public debate, and whatever solution we come up with will largely be influenced by governmental actions, whether we like it or not.

Another part of the frustration is, that the public debate generally does not deal in the trade-offs which I eluded to before. Instead, the public debate deals in emotions, absolutes, and contradictory statistics, and finally and unfortunately the distrusts of individuals, institutions, and what have you. Part of the danger of the whole thing is that he who argues best is not always right. I believe that it is our duty, our collective duty, to participate in these debates, whether we like that or not—to use our knowledge, our backgrounds, what we bring to this, because we are all experts in our own areas, to elevate the quality of the public discussion and to dispel myths wherever possible.

Some things aren't ever clear, at least they seem not to be, and I suspect that it is a fairly good consensus in this group. Such developments as solar energy and fusion reactors and other advanced systems to produce power will not be very much help to us, or be available at all during this century. We need to rely on coal, nuclear power, and energy conservation. Coal is our subject here today and we need to agree on how to use it in a way that reasonable people, be they in government or in industry, can plan, obtain financing, and construct the necessary facilities to produce the power that we need. And to do this in a reasonable time scale so that they can react to our uncertainties and demands.

Technology can help in this. It can make the decisions a little bit easier. It can make them somewhat less costly. It can reduce inflationary impact. We have the potential for the technological innovations. In regard to coal cleaning—it is an option. I think that is clear. Its existing technology is in terms of physical beneficiation; there may be a potential technology in terms of chemical beneficiation. Coal cleaning does not solve all of the problems—I think that we all recognize that—but its availability does ease the pressure on other parts of the energy delivery system.

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The purpose of this meeting is to focus on this option and in these sessions today we will focus on how and when this option might be buyable. For example, our panel this afternoon will deal with five sides of the public debate that I alluded to before. There are many more than five sides to that but that is only a microcosm of the total problem. I hope that you find today interesting and useful in regard to the individual roles that we play with regard to solutions to the national energy problem. Thank you.

COAL CLEANING APPLICATIONS FOR SO_2 EMISSION CONTROL

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INTRODUCTION

Coal is one of our most abundant sources of energy. Even with the enhanced role that coal will play in the future, known reserves are estimated to be sufficient for at least three or four centuries. The utilization of this form of fossil fuel leads to various well known environmental problems. In each step from the mine to utilization, various contaminants are released into the environment. The dust and gases in mines, drainage from coal mines and refuse, and stack emissions from coal-fired systems are examples of environmental problems that continue to be of concern. In addition, the presence of trace quantities of certain elements and components that are potentially hazardous pollutants may pose health or ecological risks.

Although, expanded coal production is a major goal of our nation's energy policy, such expansion cannot occur at the expense of environmental quality. Hence, the goal is expanded production with concurrent improvement in the control of pollution from coal use.

Sulfur oxide air pollution emissions from coal combustion exceeded 20.5 million tons in 1974. With the increasing use of coal as an energy source, improved methods are needed for the control of this pollutant. Major strategies for the control of SO_2 emissions include the use of coal cleaning, the combustion of coal in chemically active fluidized beds, the removal of pollutants by flue gas scrubbing, and the generation of clean synthetic fuels. An economically attractive control strategy is coal cleaning. This paper presents the current status of coal cleaning technology and discusses barriers that must be overcome before this technology can be widely implemented for SO_2 emission control.

DISCUSSION

Coal Contaminants

The sulfur content of coal normally ranges from less than 1 to about 7 percent, as indicated in Figure 7-1, which lists the range of composition of the major elements associated with the inorganic constituents of coal. Sulfur appears in coal in three forms: mineral sulfur as FeS_2 either in the form of pyrite or its polymorph marcasite, organically bound sulfur, and trace quantities of "sulfate" sulfur. Pyrite and marcasite occur in coal seams in sizes ranging from small discrete particles to large lumps. They can be found intimately dispersed in the coal substance, in bands, in layers, or in large pieces. Postulated modes of association and the physical forms in which the inorganic sulfur occurs are provided in Figure 7-2.(1) Sulfate sulfur occurs in coal as a result of the attack of oxygen on the mineral pyrite. It is soluble in water and can be removed in wet coal preparation plants. Organic sulfur occurs as part of the organic coal structure and can only be removed by chemical coal preparation techniques or during conversion to gaseous or liquid fuels.

Sulfur leads to serious pollution problems in both air and water. The oxidation of FeS_2 and other forms of sulfur to SO_2 during the combustion process leads to the stack emission of SO_2, as illustrated by the first equation in Figure 7-3. The combined action of water and air leads to the generation of sulfuric acid and iron sulfate, as illustrated by the second equation of Figure 7-3. This is the predominant phenomenon causing acid mine drainage. The acidic oxidizing conditions characteristic of acid mine drainage also lead to the dissolution of organic matter, trace metals, and other constituents of coal. The presence of these components in the drainage creates the potential for ecological damage and poses possible hazards to human health.

Coal contains varying quantities of many other inorganic elements. Figure 7-1 lists major inorganic elements and their ranges of concentration. These elements make up the bulk of the ash or mineral residue that remains after combustion.

Coal contains trace quantities of many other elements. Those considered to be of environmental concern and the range of their concentrations are given in Figure 7-4. Concentrations of these metals range from 0.01 to 1.6 ppm for mercury to as high as 6,000 ppm for zinc.

Although some information is available on the fate of trace metals during physical coal preparation, the development of additional information is needed. A good summary assessment of existing information has been prepared by E. M. Wewerka and others of Los Alamos Scientific Laboratory.(2)

Coal Cleanability

Physical preparation or cleaning techniques will remove varying fractions of the pyritic sulfur as determined by the properties of each coal. Chemical processes are reportedly capable of removing over 95 percent of the pyritic sulfur and up to 70 percent of the organic sulfur.(3)

There are essentially two mechanisms used for physical coal cleaning (i.e., the physical separation of coal from mineral matter): those techniques that involve differences in specific gravities and those that depend upon differences in surface properties of these materials. Froth flotation is an example of the latter mechanism, while techniques such as heavy media and jigging are representative of the former.

Laboratory float-sink studies have been performed on over 455 U.S. coals to determine their physical cleanability by gravimetric techniques.(3) The samples tested were from mines in the six major coal producing regions of the U.S.—the mines which provide more than 70 percent of the coal used in U.S. utility boilers.

The results of these float-sink tests indicate that, in general, pyrite removal increases with reduced particle size and specific gravity of separation. This fact is extremely important. It implies that to enhance pyritic sulfur removal, we must increase the amount of coal that is crushed and processed at fine particle sizes and lower specific gravities. These studies also tell us that the final sulfur levels to which coals can be cleaned vary from coal region to coal region and from one coal bed to another within the same region. Coal sulfur levels and coal cleanability also vary from location to location within the same mine. These differences in physical cleaning potential are the result of variations in the organic and pyritic sulfur and the morphology of the coal-pyrite matrix.

By ignoring the effects of sulfur variability within a given mine, the number of U.S. coals that can be cleaned for compliance with SO_2 emission regulations can be estimated. Figure 7-5 illustrates that, without cleaning, only 14 percent of the 455 U.S. coals tested by the Bureau of Mines meet the current Federal SO_2 new source performance standards (NSPS) of 1.2 lb $SO_2/10^6$ Btu for steam-fired generators.(4) When physically cleaned at a top size of 1-1/2 in.* and with a limiting Btu recovery of 90 percent (no more than 10 percent of the heat from the mined coal would be lost in any case), 24 percent of these coals meet NSPS. The percentage of coal that could be cleaned to NSPS levels could be increased by either reducing the particle size of coal being cleaned or reducing the Btu recovery value of the cleaned product. In the latter case, the reject coal could probably be used in a boiler with flue gas desulfurization (FGD).

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*English to metric unit conversion factors are given at the end of this paper.

A much larger percentage of coals meet widely varying state standards. Figure 7-6 presents data on the amounts of pyritic sulfur that can be removed from coal samples from six regions by crushing to a 3/8-inch top size and by separating at a specific gravity of 1.6. As illustrated, the average fuel sulfur values for the cleaned coals from these six regions range from 0.9 to 5.5 lb $SO_2/10^6$ Btu. In all cases, the Btu recovery exceeds 91 percent. Many states have emission regulations which range from 2.0 to 5.0 lb $SO_2/10^6$ Btu and a large portion of the tested coals can be cleaned to meet these regulations. Figure 7-5 also presents the relationship between selected cleaning conditions and the number of samples that can be cleaned to meet NSPS standards based on the 455 samples experimented with by the Bureau of Mines.

The specific gravity of separation and the size fraction being cleaned are important parameters relative to sulfur reduction performance for physical coal cleaning. The effects of these variables on the cleanability of northern Appalachian region coals are illustrated in Figure 7-7. This figure indicates the necessity of crushing and cleaning coals at fine sizes to achieve a high degree of sulfur reduction. Processing of these small size fractions should permit the removal of 50 to 90 percent of the pyritic sulfur by physical cleaning, depending upon the source of the coal.

The physical cleaning of fine coal for pyrite removal requires the exploitation of phenomena other than natural differences in the specific gravities of the coal and the pyrite. One of the phenomena commonly used to achieve such separation is the differences in surface properties. Although the surface properties of coal and pyrite do not differ greatly, reagents can be used to enhance the difference and make separation possible. Specific techniques that utilize differences in the surface properties of coal and pyrite to achieve separation are:

- Conventional froth flotation
- Two-stage froth flotation
- Vacuum flotation
- Oil agglomeration
- Selective flocculation.

Combinations of these techniques with specific gravity separation can be used to remove 50 to 90 percent of the pyrite from the fine coal.

Chemical techniques are required to remove organically bound sulfur. Chemical techniques can also be used to remove nearly all the pyritic sulfur. Sulfur removal by chemical methods depends upon coal properties and process conditions—time, pressure, temperature, and chemical reagents. Process economics will probably limit the amount of sulfur that can be removed on a commercial basis to about 95 to 99 percent of the pyritic sulfur and perhaps 40 to 70 percent of the organic sulfur.

Both physical and chemical coal cleaning processes can be used to reduce the average sulfur level in the coal from certain mines to a point where the coal can be burned in compliance with existing emission standards most of the time. However, the fact that the composition and properties of coal can vary widely even within a given coal seam is an important consideration with respect to emission regulations. The wide variability of the SO_2 emissions produced by burning coal from a single mine is shown in Figure 7-8.(5) The sulfur content of samples from unit trains ranges from about 0.82 lb $SO_2/10^6$ Btu to about 1.10 lb $SO_2/10^6$ Btu.

Because the sulfur content varies, the average value for sulfur in coal can be used to determine compliance with a given standard only if long-term averaging of the resultant SO_2 emission is permitted. If, however, the emission limit includes a "never to be exceeded" statement, a coal with average sulfur and heat content values, which compute to the stated emission limit, will be out of compliance approximately half of the time. The net effect of an emission regulation that calls for anything other than long-term averaging is to require the use of coal with lower average sulfur content so that, when upward deviations from the average occur, the unit will still be in compliance. The problem is to determine how much lower the average sulfur content must be.

If the variability of sulfur in coal follows normal statistical relationships, the answer could be found by determining the standard deviation of the sulfur values. However, insufficient data exist on sulfur variability to show that normal statistics are followed. In fact, the discrete nature of pyritic sulfur in coal seems to preclude the expectation of normal statistical behavior. Nevertheless, in lieu of a more precise approach, the variability in sulfur content can be approximated by assuming that the statistics for normal distribution apply.

The general effect of sulfur variability and of different averaging times on the average emission level required is shown in the following tabulation.(6)

	Average Emission Level Required, lb $SO_2/10^6$ Btu		
Emission Standard, lb $SO_2/10^6$ Btu	**Long-Term Averaging**	**30-Day Averaging***	**24-Hour Averaging***
1.2	1.2	0.92	0.58
0.8	0.8	0.62	0.39
0.4	0.4	0.31	0.19

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*Following recent EPA practice, the relative standard deviation (RSD), defined as σ/μ where σ is the standard deviation and μ is the mean value, was taken as the measure of sulfur variability. A 10 percent RSD was used as representative of a 30-day averaging period and a 99.87 percent confidence level was adopted. For a normal distribution, this level occurs at $\mu + 3\sigma$. This means that a coal with an average SO_2 emission of μ will exceed $\mu + 3\sigma$ only 0.13 percent of the time. A 36 percent RSD and a 3σ confidence level was used as representative of a 24-hour averaging period.

It is apparent that short-term averaging requirements will greatly reduce the quantities of raw coal and of cleaned coal that could be burned in compliance with any given emission limit, because the average sulfur content required for a 24-hour averaging period is less than half that for long-term averaging.

The sulfur variability problem exists regardless of any SO_2 emission control technique that might be used. For example, coal that has been physically cleaned will still exhibit variable sulfur content. There will probably be less variation for cleaned coal than for raw coal, although there are not sufficient data to confirm that assumption. With respect to FGD, variations in the sulfur content of coal being burned will result in variations in the SO_2 emission rate. Again, the scrubber system may have some damping effect, but this has not been confirmed.

Figure 7-9 presents parametric relationships between the degree of cleaning (pyritic and organic sulfur reduction), the sulfur level of the cleaned coal, and the percentage of utility coals that can be cleaned to a specified sulfur content. This figure illustrates that about 20 percent of the utility coals would meet Federal new source standards by 90 percent removal of pyritic sulfur. Approximately 40 percent would meet these standards with 95 percent removal of pyritic sulfur and 40 percent removal of organic sulfur.

Desulfurization Techniques

Preparation of steam coal is currently oriented toward the removal of ash and mining residue. The physical removal of pyritic sulfur from steam coal has only recently(7,8) been planned as a method of SO_2 emission control. The physical removal of pyrite from many coals will require crushing to fine particle sizes prior to separation. Separation at these fine sizes, while not impossible, represents a mix of equipment and operating conditions different from that traditionally used for steam coal preparation. Dewatering and drying of a large percentage of fine coal may be required for many of the new plants.

Several different unit processes or types of equipment may be employed for the physical cleaning of coal. Individual techniques are generally applied to different size fractions, as illustrated by Figure 7-10 for gravity methods and Figure 7-11 for surface property methods. Commercial equipment is generally available for larger particle sizes, as shown in these figures. Experimental work is underway to demonstrate techniques for smaller sizes, generally under 100 mesh. Except for air tables, water is generally the washing medium employed. Magnetite is usually added for equipment that uses a heavy medium, although anhydrous heavy liquids have been examined in the laboratory and one such process(9) is currently under development.

The removal of the organically bound sulfur from coal will require the application of nonphysical techniques. Most experimental work has been devoted to chemical coal cleaning. Chemical coal cleaning is in the early stages of development, and it is estimated that a commercial plant could not be put into operation for at least 5 to 10 years. Figure 7-12 summarizes several chemical coal cleaning processes now under development. Note that not all of these processes are applicable for organic sulfur and that none is expected to remove even half of the organically bound sulfur. More technically effective processes may be developed in the future, but the economic feasibility of removing a major fraction of the organic sulfur from coal in the foreseeable future is uncertain. However, as illustrated by Figure 7-12, chemical processes may be used to remove essentially all of the pyritic sulfur.

Although coal cleaning processes may be used advantageously in helping to control the emission of SO_2 from coal combustion sources, these processes also have environmental consequences. Coal cleaning plants are potential sources of fugitive dust, acid runoff, SO_2, trace metals, and other pollutants. Thus, coal cleaning processes have multi-media environmental impacts and pollution control techniques must be used to minimize or eliminate these impacts. The effectiveness and cost of such controls and of coal cleaning processes must be weighed against other techniques for SO_2 control.

The major objective of coal cleaning for sulfur control is to reduce the SO_2 stack emissions when coal is combusted. Generally, solid wastes from coal combustion will also be reduced because of the lowered ash content of the cleaned coal. However, some environmental pollution does result from coal cleaning processes. Atmospheric pollution may occur from coal handling, coal refuse disposal, and from coal thermal dryer emissions. Careful design is required to mitigate water pollution problems that may result from refuse leaching, from acid drainage associated with refuse piles, and from the slurries and process water flows. Proper utilization of impoundments and other techniques will prevent the pollution of water courses. Thus, it is seen that reduced SO_2 stack emissions and reduced solid wastes from coal combustion are traded off against problems in controlling the pollutant discharges from coal preparation. EPA is now evaluating these environmental trade-offs and will be able in the near future to quantify the relative environmental impacts of physical coal cleaning and flue gas desulfurization, two major SO_2 emission control techniques.

Desulfurization Processes for SO_2 Emission Control

The techniques or equipment described earlier may be combined in a wide variety of ways to form different coal cleaning processes. A wide variation in levels of physical cleaning is found in commercial practice. Several authors have subdivided the degree of preparation into a number of levels of cleaning.(13,10,11) The levels vary from no preparation at all to elaborate configurations designed for pyrite removal, ash removal, and optimal Btu recovery. To simplify the discussion of various degrees of cleaning, it is convenient to define five levels of coal cleaning as shown in Figure 7-13.

Breaking and screening results in removal of gross, noncombustible impurities and some control of particle size and promotion of uniformity. Material yield and heat (Btu) recovery are very high, perhaps 95 percent and 99 percent, respectively. However, the sulfur content is essentially unchanged.

Coarse cleaning consists of cleaning larger size fractions, usually those greater than 3/8 inch, using one or more gravity separation techniques; e.g., jigs. Fine coal fractions are usually not cleaned and are blended directly with the cleaned coarse coal. In some cases, the fine coal stream is used for a different purpose or some ultrafine fraction is discarded. Material yield and heat recovery depend upon the extent to which the fine fractions are utilized or discarded, approaching 80 percent and 95 percent, respectively, for maximum utilization of fines.

The incorporation of a fine coal cleaning circuit can result in significant sulfur reduction without excessive Btu losses. However, cleaning fine coal in a wet process does introduce the need for coal drying and the attendant cost and energy penalties. Thus, the net heat recovery in the process is reduced correspondingly. Capital and operating costs are also increased because of increased complexity of the plant.

Variations in coal composition and differing specifications for the clean coal to meet consumer and environmental demands lead to the need for coal cleaning plants of varying complexity. For each particular situation it is possible to optimize the coal preparation plant; i.e., to design the plant to provide the maximum pyrite removal and Btu recovery at the lowest cost consistent with emission regulations and the resultant coal energy values. Such plants may include multiple circuits for different size fractions, fine grinding equipment, dewatering devices, and thermal dryers for the finer size fractions. A need may exist for more than one product quality; e.g., addition of a generating unit that must comply with new source standards at a facility with already operating older units. In this case, the product stream separated at very low gravity may be used to meet the new source standards and the low-gravity reject stream further processed to obtain fuel that can be used in the older units in compliance with existing source standards. Such a multi-stream coal cleaning system is under construction at Homer City, Pennsylvania. This system is discussed by J. F. McConnell in another paper in this conference.

Strategies for SO_2 Emission Control

A strategy for SO_2 emission control may be selected for each individual case. The strategy chosen will depend upon the coal and the applicable emission standards. A range of possible strategies is given below.

- Partial physical cleaning for easily cleaned coals with pyrite removal to meet standards
- Full physical cleaning to produce one or more coal products, each with a specified sulfur level
- Combinations of physical cleaning and flue gas desulfurization for coals with relatively high organic sulfur content or as needed to meet stringent SO_2 emission standards
- Combinations of physical and chemical coal cleaning for difficult-to-clean coals or stringent emission standards.

The first two strategies have been discussed and processes for these strategies can be designed from commercially available systems for certain coal-emission standard combinations.

The use of physical coal cleaning in combination with flue gas desulfurization represents an approach where the advantages of each technique can be used to minimize emission control costs while permitting the most effective use of U.S. coal resources. Estimated costs for combinations of physical coal cleaning and FGD versus FGD alone have been compared. Significant savings appear possible by utilizing the combination approach to comply with existing state and Federal standards. Lawrence Hoffman and A. W. Deurbrouck discuss this study in another paper in this symposium.

The use of physical coal cleaning in conjunction with chemical coal cleaning may be an attractive approach for meeting stringent standards. This is particularly attractive if sorbents for FGD are not available or sulfate disposal in the specific location is not environmentally sound. For small boilers—where unit costs for FGD are prohibitively high—physical or chemical coal cleaning can be especially useful for controlling emissions.

The depletion of reserves of crude oil and natural gas in this country leads to the postulation of a coal refinery complex, as indicated by Figure 7-14. Such an approach could provide clean solid fuels for steam boilers, clean gaseous and/or liquid fuels for distribution, and raw materials for production of organic coal chemicals. These same organic chemical products are generally produced today by refining crude oil fractions and from raw materials derived from crude oil and natural gas. However, processing of coke oven gas to produce such chemicals in this country dates back to the 1940's.

Other Technology Development Requirements

Physical cleaning is widely used on a commercial basis and chemical cleaning is in an early development stage. Ancillary to the basic cleaning processes are requirements for effective instrumentation and controls to deal primarily with variation in coal feed. These are discussed briefly below.

The variability of sulfur forms within a coal bed or mine presents a special problem that will require the development of improved technology if coal cleaning is to be used for SO_2 emission control. Methods are needed for controlling the sulfur variation in the plant feed and process instrumentation is needed to control the product sulfur level.

The coal preparation plant performance in removing pyritic sulfur can be seriously affected by wide variations in feed coal properties. Development of mining and blending schemes to minimize the pyritic sulfur variations in the feed coal will be needed to insure a product coal that consistently meets fuel sulfur requirements. Currently, there is little published data on the variability of fuel sulfur forms in coal beds. The effects of mining, blending, and preparation plant operations in "averaging out" the cleaned coal sulfur level are unknown. Because of these factors, the cleaning plant must now be designed to remove sufficient pyritic sulfur that, even at peak raw coal sulfur levels (both organic and pyritic), the product coal sulfur will be maintained below the level required by the fuel sulfur emission regulation. This approach may not be practical in cases where it would require the rejection of large quantities of fuel that do not, on the average, exceed the emission regulation.

A long-term objective would be to develop process instruments and controls that could be used to adjust plant operating conditions in response to the changes in the feed coal sulfur content. This method of control would allow optimization of sulfur removal and Btu recovery. Unfortunately, instruments that can be used for a real time determination of coal sulfur, ash, and Btu values are not commercially available.

Economic Factors

Accurate estimates of costs involved for SO_2 pollution control facilities, including physical coal cleaning facilities designed for that purpose, must, of necessity, be prepared on a case-by-case basis. However, some generalized comments and observations are presented. Valid comparisons must be drawn from consideration of the total system; i.e., mining, transportation, storage, preparation or cleaning, boilers, and pollution control including solid waste disposal.

Estimates of physical coal cleaning costs will depend primarily on:

- Plant complexity required to contend with (a) coal cleanability, (b) fuel sulfur specifications, and (c) number of products
- Coal replacement costs
- Plant capacity
- Environmental regulations.

Plant capacity is a major factor affecting unit energy cleaning costs, as illustrated by Figure 7-15. This example includes both coarse and fine cleaning circuits and illustrates reduced costs per unit energy for higher capacities. This, in turn, suggests the economic attractiveness of large, multi-purpose, mine-mouth cleaning facilities.

Physical coal cleaning circuits become increasingly complex as additional equipment is added to maximize coal recovery and the rejection of pyrite and other potential pollutants. Complex circuitry leads to increased capital and operating costs, which must be balanced against the benefits of cleaner coal and the costs of alternative techniques for controlling SO_2 emissions. For many coals, the complexity required to achieve a high degree of pyrite removal may be excessive and the production of multiple product streams, which in itself leads to complexity, may be the only economically attractive solution.

Another important cost factor is the replacement cost for the energy content lost in the refuse. For each ton of product coal, this energy loss must be replaced by buying an incremental amount of replacement coal. Figure 7-16 shows the effects of coal replacement costs and Btu recovery on annualized coal cleaning costs. The range of flue gas desulfurization costs is also shown. For raw coal costs of less than \$1.00/10^6 Btu and Btu recovery greater than 85 percent, coal cleaning provides a more economic alternative than FGD. Thus, for this case, if a specific coal costing no more than \$1.00/10^6 Btu can be cleaned to meet standards with a Btu recovery of 85 percent or more, physical cleaning is the more attractive alternative.

Standards and guidelines that have been recommended or adopted for controlling emissions from coal preparation plants also will have a significant impact on the viability of coal cleaning as an SO_2 control alternative. The use of closed-loop-process water circuits, the need to collect and treat runoff from coal and refuse storage areas, and the incorporation of systems for controlling particulate and SO_2 emissions from thermal dryers are examples of factors that add to the capital and operating costs of coal preparation plants. These, as well as other emission control costs, must be considered in determining the economic feasibility of coal preparation or combinations of coal preparation and FGD for SO_2 control.

If the specific coal cannot be physically cleaned to meet standards, other methods or combinations, as previously discussed, must be used. Figure 7-17 shows relative costs for various pollution control methods ranging from the most economic—physical cleaning—to the most expensive—gasification. Gasification and liquefaction are obviously expensive approaches for sulfur control for boiler fuels.

Barriers to the Implementation of Coal Cleaning Technology

Technical and Regulatory Uncertainties. There is still considerable economic risk related to technical and regulatory uncertainties which act as effective barriers to the implementation of physical coal cleaning as an SO_2 emission control strategy. Coal cleaning as a tool for meeting SO_2 emission regulations has been used only in a few isolated cases, generally with easily cleaned coals. The results of these efforts have not yet been widely published. The principal economic risk is related to the requirement for meeting consistent fuel sulfur specifications. In a given plant, the mix of equipment or the process controls may not prove to be adequate to consistently remove pyritic sulfur to the required degree. Technical solutions to this problem would involve a number of economically unattractive alternatives:

- Adjust the preparation plant operating conditions in a manner which would reduce the fuel recovered from the plant feed
- Make extensive equipment modifications
- Add a partial FGD system to the boiler.

A great deal of this economic risk could be reduced by more flexible regulatory activities. The modification of existing emission regulations to permit emissions to be averaged over an extended time period, say 30 days, would greatly alleviate this risk. In cases where a mix of emission regulations apply to a single site, the use of a site average emission regulation could, in some instances, reduce control costs and risks.

Other technical or regulatory uncertainties include:

- The costs of pollution control requirements for advanced coal preparation plants
- Changes in boiler operating and maintenance costs which result from the firing of cleaned coal
- The effects of firing cleaned coal on the performance of electrostatic precipitators.

Extensive commercialization of physical coal cleaning for SO_2 emission control probably cannot be expected until these uncertainties are resolved.

Institutional and Economic Barriers. A number of institutional and economic barriers block implementation of the use of coal cleaning for SO_2 emission control. Among these barriers are existing investments and contracts, the dependency of the utility industry upon other organizations for its fuel supply, a limited supply of personnel familiar with coal cleaning, and the high cost of capital.

Vertical integration in the utility industry is becoming more common as utilities attempt to secure a reliable coal supply at stable prices. However, many utilities do not own their own fuel resources. A large percentage of coal resources are owned by railroads, steel companies, coal companies, oil companies, and the private sector. The common practice is to obtain coal through short- or long-term contracts. The coal supplier has traditionally cleaned his coal primarily to remove ash and mining residue. In today's coal market there is not a clear recognition by the supplier of clear cost differentials based upon the coal sulfur levels. The supplier thus does not have an economic incentive to clean his coal with the objective of removing sulfur. While the coal industry enjoys a growing market, investment is largely directed to expansion of capacity through the opening of new mines, to safety, and to meeting environmental regulations. Incentives for coal cleaning in the coal industry must come from the market (utilities), regulatory activities, or tax laws. None of these incentives now exists.

Utilities can contract with coal suppliers for coal cleaning, or they can clean the coal themselves. However, in some instances, current investments and contract commitments are disincentives to this action. An example of these disincentives is the extensive use of Pittsburgh bed coal by utilities in the Appalachian region. A number of coal companies have high investments in existing mines and a number of utilities have long-term contracts for this Pittsburgh bed coal. This coal is high in organic and pyritic sulfur and cannot be easily cleaned to meet Federal and state regulations. However, the costs of breaking existing contracts, developing new mines, and constructing coal preparation plants may be greater than of using this coal with FGD in either existing or new generating units.

Another problem in implementing coal cleaning technology is that of identifying coal reserves that are adaptable to physical cleaning. Although cleanability studies have been performed by the Bureau of Mines, their work has been restricted to coals available from existing mines. Cleanability data are also needed on coal seams and geographic areas not currently developed. In this way, promising new resources can be identified for development.

Difficulties in raising capital may also serve as a barrier to implementation. Investors may be reluctant to support the capitalization of coal cleaning facilities because of the technical and regulatory uncertainties involved. Existing tax credits for equipment depreciation may also favor FGD over coal cleaning. Low interest rate government loans, positive environmental regulations, and modified tax laws could eliminate this economic barrier.

The lack of familiarity of the utility industry with coal cleaning as a pollution control technique may also serve as a barrier to implementation. New technology is adopted in an industry only after it has been adequately demonstrated and accepted as a viable technology by a majority of the industry members. This barrier to implementation can best be overcome by joint government/industry research, development, and demonstration (RD&D) activities. The utilities involved in this RD&D activity must be deeply involved and must eventually be committed to the development of new technology for the entire industry. The utility industry has not been oriented toward RD&D, and the development of government/industry teams is difficult. Current economic limitations on utility and government manpower available for RD&D compound this difficulty.

CONCLUSIONS

Physical coal cleaning can be used to meet a variety of state and Federal SO_2 emission regulations, singly or in combination with flue gas desulfurization. There is an increasing awareness by the coal and utility industries of coal cleaning as a method of SO_2 control. The following advantages lend attractiveness to the technique:

- It is possible in the near term.
- It is relatively low cost.
- It is applicable to both small and large boilers.
- It may be used for compliance with many state standards.

However, the following disadvantages must be considered on a case-by-case basis:

- It is not applicable for all coals and all standards.
- Coal sulfur variability, in both content and form, leads to poor product quality control.
- The locations and quantities of cleanable reserves are uncertain.
- Cost, regulatory, and institutional uncertainties prevent definitive plans.

Taking these facts into consideration, it may be concluded that:

- The technology is commercially available.
- It is the lowest cost control method for some coals.
- It has a large potential for small boilers, particularly those less than 250 million Btu/hour which do not have to meet new source performance standards.
- It is not, however, universally applicable.
- Cost, regulatory, and institutional uncertainties inhibit its rate of implementation.

Conversion Factors

ton = 0.907 metric tons
lb = 0.454 kg
Btu = 1054.8 joule
Btu/lb = 2323 joule/kg

Tyler Mesh Size	Opening, mm
14	1.168
28	0.589
100	0.147
200	0.074
325	0.043

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(6) Hall, E. H., et al., "Physical Coal Cleaning for Utility Boiler SO Emission Control", EPA-600/7-78-034 (PB 227408/AS), February, 1978.

(7) Daub, Charles H., "The Oneida Plant", *Mining Congress Journal*, July, 1974.

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(9) Keller, D. V., Jr., C. D. Smith, and E. F. Burch, "Demonstration Plant, Test Results of the Otisca Process Heavy Liquids Beneficiation of Coal", presentation to the Annual SME/AIME Conference, Atlanta, Georgia, March, 1977.

(10) Lovell, H. L., Notes from a Short Course on Coal Preparation, University Park, Pa., October 11-13, 1976.

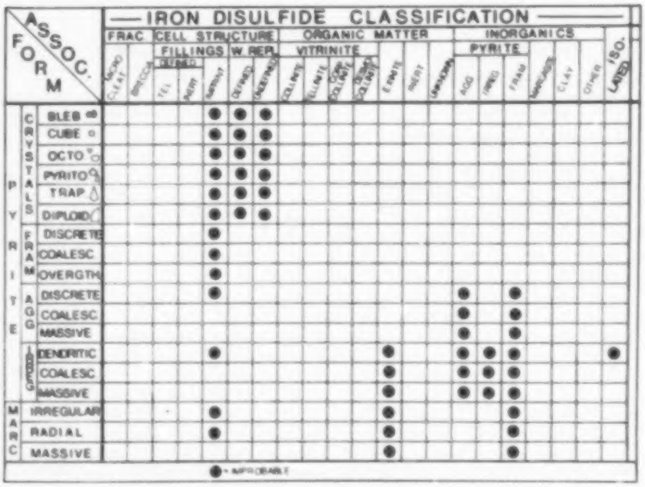
(11) Phillips, P. J., and P. P. DeRienzo, "Steam Coal Preparation Economics", presented at NCA/BCR 2nd Symposium on Coal Preparation, Louisville, Ky., October, 1976.

ELEMENT	RANGE (WT%)
SULFUR[(a)]	0.2 - 7.0
SILICON	0.6 - 6.1
IRON[(b)]	0.3 - 4.3
ALUMINUM	0.4 - 3.1
CALCIUM	0.1 - 2.7
POTASSIUM	0.1 - 0.4
MAGNESIUM	0.1 - 0.3
TITANIUM	0.0 - 0.3
SODIUM	0.0 - 0.2

(a) Subject to Federal and State Emission Regulations
(b) Proposed EPA Effluent Limitations for Coal
Mining Point Sources

MAJOR ELEMENTS ASSOCIATED WITH INORGANIC CONSTITUENTS OF COAL

FIGURE 7-1


IRON DISULFIDE CLASSIFICATION
ASSOC.
FORM
FRAC
CELL STRUCTURE
FILLINGS
W REPL
ORGANIC MATTER
VITRINITE
INORGANICS
PYRITE
ISO-LATED
BLEB
CUBE
OCTO
PYRITO
TRAP
DIPLOID
DISCRETE
COALESC
OVERGTH
DISCRETE
COALESC
MASSIVE
DENDRITIC
COALESC
MASSIVE
IRREGULAR
RADIAL
MASSIVE
P Y R I T E
C R Y S T A L S
F R A M
A G G
M A R C

PHYSICAL CHARACTERISTICS OF IRON DISULFIDE

FIGURE 7-2

SULFUR OXIDE EMISSIONS

$$4\ \underline{FeS_2} + 11\ 0_2 \rightarrow 2\ Fe_2 0_3 + 8\ \underline{SO_2} + \triangle$$

ACID MINE DRAINAGE

$$2\ \underline{FeS_2} + 2\ H_2O + 7\ O_2 \rightarrow 2\ FeSO_4 + 2\ \underline{H_2SO_4} + \triangle$$

$\triangle$ = HEAT

IRON SULFIDES CAUSE MAJOR ENVIRONMENTAL PROBLEMS

FIGURE 7-3

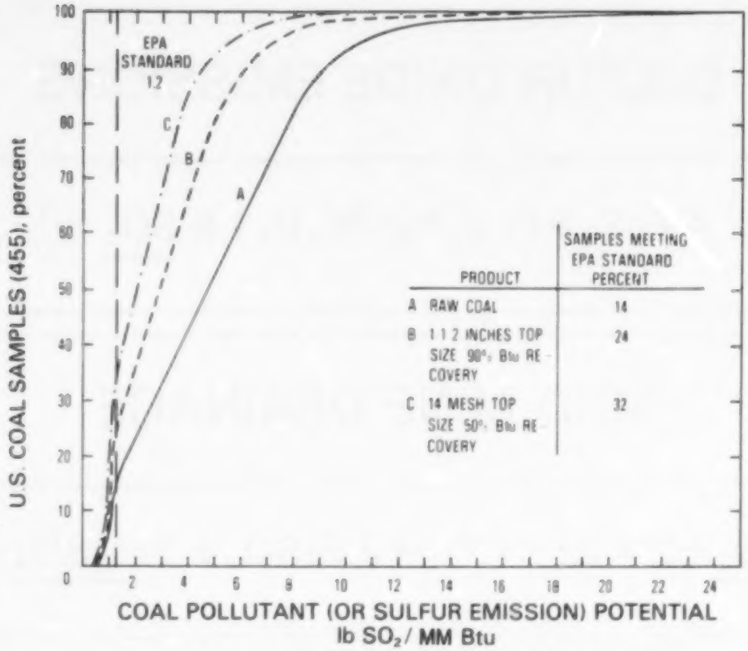
ELEMENT[a]	RANGE (ppm)
BERYLLIUM	0 - 31
MANGANESE[b]	6 - 181
NICKEL	0.4 - 104
COPPER	2 - 185
ZINC	0 - 6000
ARSENIC[c]	0.5 - 106

ELEMENT[a]	RANGE (ppm)
SELENIUM[c]	0.4 - 8
YTTRIUM	0.1 - 59
CADMIUM	0.1 - 65
MERCURY	0.01 - 1.6
LEAD	4 - 218

(a) In order of increasing atomic weight.
(b) Proposed EPA effluent limitation for coal mining point sources.
(c) Concentrations on average greater than earth crustal abundance.

TRACE ELEMENTS OF ENVIRONMENTAL CONCERN IN COAL

FIGURE 7-4



EFFECT-OF-CLEANING VARIABLE ON COAL POLLUTION POTENTIAL

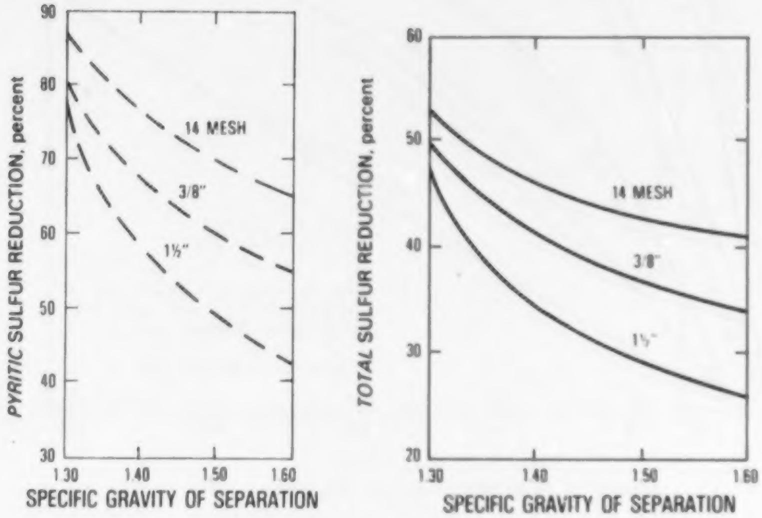
FIGURE 7-5

CUMULATIVE ANALYSES OF FLOAT 1.60 PRODUCT FOR 3/8 TOP SIZE

		PERCENT					
COAL REGION	NO. SAMPLES	Btu RECOVERY	ASH	PYRITIC SULFUR	TOTAL SULFUR	POUNDS SO /10^6 Btu	CALORIFIC CONTENT, Btu PER POUND
NORTHERN APPALACHIAN	227	92.5	8.0	0.85	1.86	2.7	13,766
SOUTHERN APPALACHIAN	35	96.1	5.1	0.19	0.91	1.3	14,197
ALABAMA	10	96.4	5.8	0.49	1.16	1.7	14,264
EASTERN MIDWEST	95	94.9	7.5	1.03	2.74	4.2	13,138
WESTERN MIDWEST	44	91.7	8.3	1.80	3.59	5.5	13,209
WESTERN	44	97.6	6.3	0.10	0.56	0.9	12,779
TOTAL U. S.	455	93.8	7.5	0.85	2.00	3.0	13,530

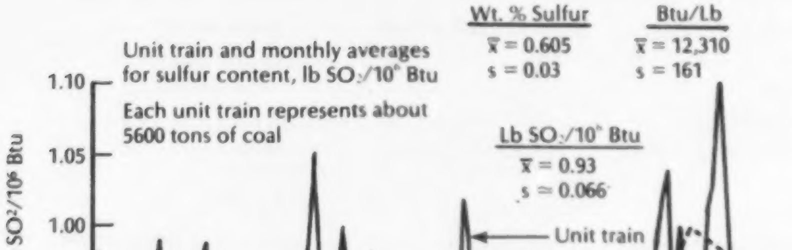
SUMMARY OF THE PHYSICAL DESULFURIZATION POTENTIAL OF COALS BY REGION

FIGURE 7-6



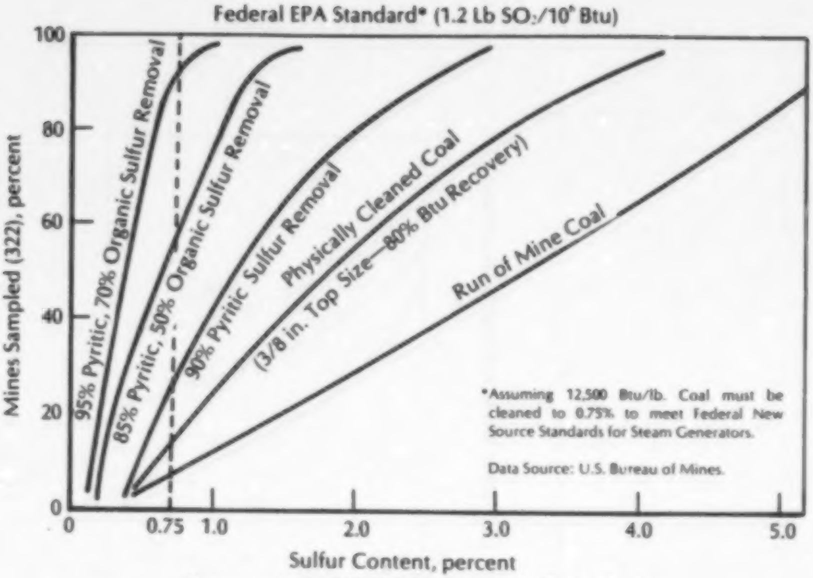
SULFUR REDUCTION FOR NORTHERN APPALACHIAN REGION COALS

FIGURE 7-7



VARIATION IN SULFUR CONTENT WITH TIME, DATA SET C-2(5)

FIGURE 7-8



*Assuming 12,500 Btu/lb. Coal must be cleaned to 0.75% to meet Federal New Source Standards for Steam Generators.

Data Source: U.S. Bureau of Mines.

Source: EPA-600/7-76-024, p. 62, Figure 2.1.3

POTENTIAL LEVELS OF DESULFURIZATION FOR U.S. UTILITY COALS

FIGURE 7-9

Method of Separation	Size of Typical Feed	Status of Use
Washing		
Jigs, Launderers	4 to 1/4 inch	Commercial
Concentrating Table	3/8 inch to 35 mesh minus 30 mesh	Commercial Experimental
Hydrocyclone	minus 1/4 inch	Commercial
Concentrating Spiral	minus 30 mesh	Commercial and Experimental
Dense Medium		
Laminar Flow	4 to 1/4 inch	Commercial
Cyclone	3/8 inch to 32 mesh	Commercial
Air Concentration		
Jigs, Tables, Launderers	3/8 inch to 48 mesh	Use diminishing
Classifiers	80% minus 200 mesh	Commercial and Experimental
Centrifugal	70% minus 200 mesh	Experimental

GRAVITY SEPARATION METHODS

FIGURE 7-10

Method of Separation	Size of Typical Feed	Status of Use
Froth Flotation		
Conventional	minus 28 mesh	Commercial
Two-Stage Vacuum	minus 28 mesh minus 14 mesh	Pilot Plant Experimental
Oil Agglomeration		
Trent	minus 28 mesh	Experimental
Convertol	minus 325 mesh	Pilot Plant
Spherical Agglomeration	minus 200 mesh	Commercial in Canada
Selective Flocculation	40 microns or less	Experimental

SEPARATION METHODS BASED ON SURFACE-PROPERTY DIFFERENCES

FIGURE 7-11

PROCESSES UNDER DEVELOPMENT	*DESCRIPTION*	*MAX. SULFUR REDUCTION, PERCENT*		*STATUS*
		PYRITIC	*ORGANIC*	
ARCO	CATALYTIC DEMETALLIZATION	95	40	LABORATORY EXPERIMENTS
BATTELLE HYDROTHERMAL	CAUSTIC LEACHING [$NaOH$-$Ca(OH)_2$]	95	40	0.25 tpd MINI-PLANT
ERDA, BRUCETON, PA	OXI-DESULFURIZATION (AIR-STEAM)	99	40	LABORATORY EXPERIMENTS; DESIGN OF CONTINUOUS UNIT
TRW	AQUEOUS FERRIC SULFATE LEACHING [$Fe_2(SO_4)_3$]	95	NIL	LABORATORY EXPERIMENTS; CONSTRUCTION OF A 1/3 ton/hr TEST UNIT

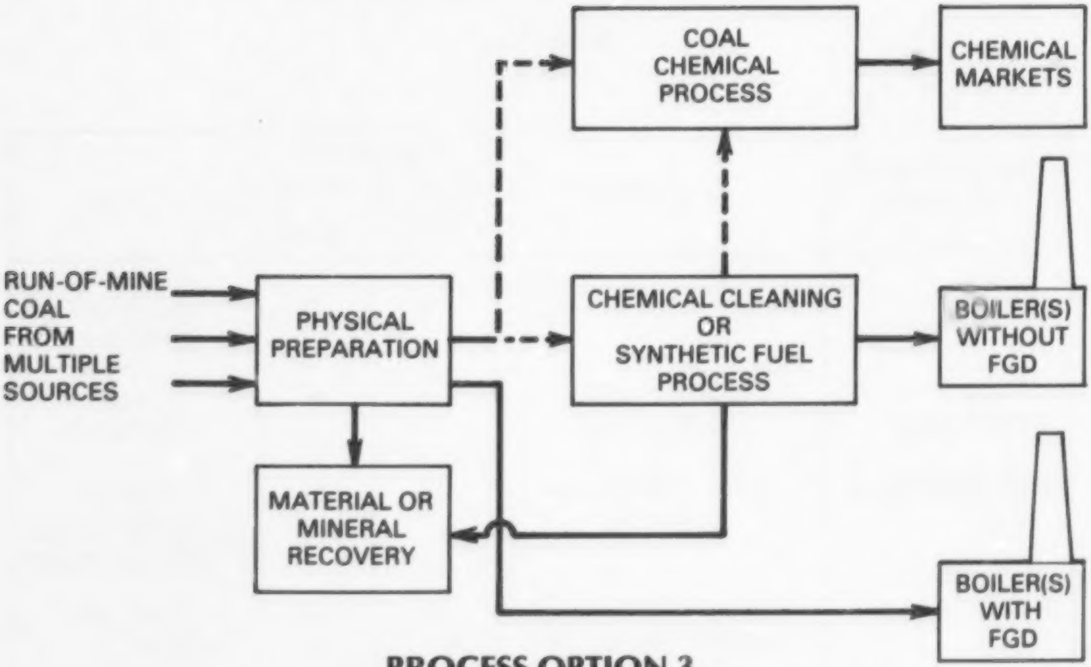
STATUS OF SELECTED CHEMICAL TREATMENT PROCESSES

FIGURE 7-12

- Absence of Preparation
- Breaking and Screening
- Coarse Cleaning, Fines Unprocessed
- Full Cleaning, Fines Processed
- Optimum Preparation
  - Pyrite removal
  - Ash removal
  - Btu recovery

LEVELS OF CLEANING

FIGURE 7-13


COAL CHEMICAL PROCESS
CHEMICAL MARKETS
RUN-OF-MINE COAL FROM MULTIPLE SOURCES
PHYSICAL PREPARATION
CHEMICAL CLEANING OR SYNTHETIC FUEL PROCESS
BOILER(S) WITHOUT FGD
MATERIAL OR MINERAL RECOVERY
BOILER(S) WITH FGD

PROCESS OPTION 3, COAL REFINERY COMPLEX

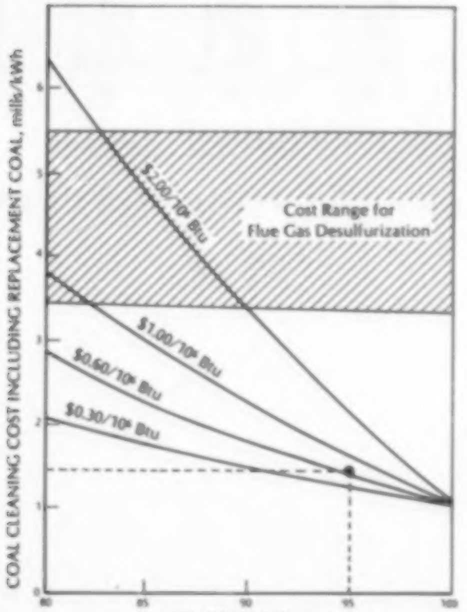
FIGURE 7-14

	Coal Cleaning Plant Capacity, tons/hour		
	125	500	1000
Capital			
Direct, million $	5.8	9.8	14.2
Indirect, million $	2.8	4.9	6.9
Contingency, million $	1.7	3.0	4.2
Land, million $	0.1	0.4	0.8
Total, million $	10.4	18.1	26.1
Total, thousand $/(ton/hour)	83.3	36.2	26.1
Annual			
Fixed, million $	1.9	3.4	4.9
Operating and maintenance, million $	1.6	2.8	4.3
Replacement cost(a), million $	0.3	1.3	2.6
Total, million $	3.8	7.5	11.8
Total, $/ton	7.7	3.8	3.0
Total, mills/kWh(b)	3.7	1.8	1.6

(a) At $0.60/10⁶ Btu, 5% Btu loss, 11,000 Btu/lb, 3690 hr/yr.
(b) At 10,000 Btu/kWh.

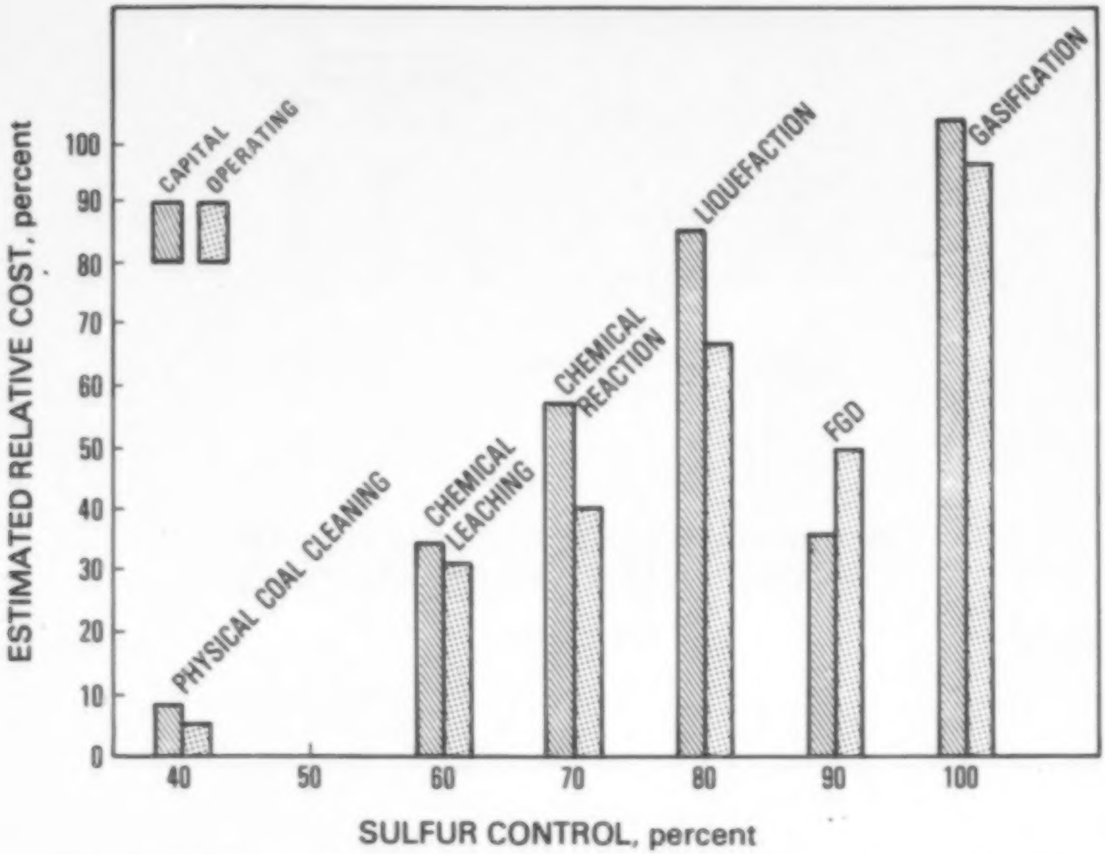
PREPARATION COSTS AS A FUNCTION OF CAPACITY (COARSE AND FINE CLEANING)

FIGURE 7-15



COST AS A FUNCTION OF COAL COST AND BTU RECOVERY EFFICIENCY (1000 TPH COARSE AND FINE CLEANING)

FIGURE 7-16



COSTS FOR VARIOUS SULFUR POLLUTION CONTROL METHODS

FIGURE 7-17

ENGINEERING/ECONOMIC ANALYSES OF COAL PREPARATION WITH SO_2 CLEANUP PROCESSES FOR KEEPING HIGHER SULFUR COALS IN THE ENERGY MARKET

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Bureau of Mines

INTRODUCTION AND BACKGROUND

A concern for preserving the quality of the environment resulted in the Air Quality Act of 1963 which initiated a concerted effort by Federal, state, and local governments for the preservation of the Nation's air quality. This Act called for an expanded Federal research and development program and placed special emphasis on the problem of sulfur oxide emissions from the combustion of coal and oil in stationary plants.

Currently and potentially available methods for controlling sulfur oxide emissions from coal-fired stationary combustion sources fall into the following categories:

1. The use of low sulfur coal either naturally occurring or physically cleaned
2. Removal of sulfur oxides from the combustion flue gas
3. Chemical treatment to extract sulfur from coal
4. Conversion of coal to a clean fuel by such processes as gasification and liquefaction.

Of these methods, for amenable coals, physical removal of pyritic sulfur (principally FeS_2) is the lowest cost and has the most developed technology. Even so, the potential total sulfur reduction is limited since organic sulfur cannot be removed by this process. Another approach to controlling SO_2 emissions, could be the combined use of physical cleaning followed by stack gas scrubbing. The potential benefits derived from combined physical cleaning and flue-gas desulfurization include: (1) the ability to utilize high-sulfur coal with minimal to moderate physical cleaning, (2) the availability of a more uniform coal, (3) lower effective transportation costs, (4) reduced maintenance costs, and (5) lower coal grinding and ash disposal costs.

Sulfur in coal exists in two principal forms, organic and inorganic. The organic sulfur is bound chemically to the coal substance and cannot be physically removed. However, inorganic sulfur (i.e., pyritic) is not bound chemically with the coal substance and may be removed to varying extents by crushing and physical cleaning. The degree of removal is dependent upon pyrite size and distribution, coal size, and other physical characteristics.

Physical cleaning of coal has been used for many years. Its principal purpose has been to reduce the so-called ash-forming impurities. If any of the impurities are pyritic, it would also reduce the sulfur in the coal. The process in common use for reducing such impurities is a combination of stage crushing and specific gravity separation. Shale and coal having different specific gravities may be separated. Froth flotation, dependent on differences in surface characteristics of coal and refuse, is used for removing impurities from very fine size coal. Existing cleaning processes, while removing impurities from coal, also reduce the total Btu recovery (i.e., a portion of the heat content of the feed will be lost with the refuse). However, the Btu content per unit weight of the processed product increases due to removal of low heat value impurities.

In 1965, EPA sponsored a study to quantify the impact that coal cleaning, optimized for pyrite removal, could have on the control of sulfur oxide emissions. They found that it was impossible to quantify the impact of coal cleaning on sulfur oxide emissions because of large gaps in available information. The study identified the following areas where required information was either not available or was inadequate for appraising this impact:

- Knowledge of the distribution of sulfur forms in (all) major utility-coal producing coalbeds in the United States;
- Effectiveness of available commercial coal preparation methods for pyrite separation, together with the development and/or modification of these techniques to maximize sulfur reduction;
- Identification and assessment of processes that could economically utilize coal cleaning reject material for by-product recovery, thereby aiding the overall cleaning economics and reducing potential air, water, and solid pollution.

The findings of the 1965 study led EPA to proceed with implementation of a comprehensive program designed to define the role of coal cleaning in controlling sulfur oxide emissions from coal fired sources. An important part of the program was to determine the extent to which the sulfur content of U.S. coals could be reduced by coal cleaning processes based on differences in physical properties. While pyritic sulfur is amenable to removal by such processes, the other major form of sulfur (organic sulfur compounds) is not. A good indicator of the "cleanability" of pyrites from a coal is the specific gravity analysis, or float-and-sink test, in which the crushed coal is tested at various specific gravities to effect a separation between coal and impurities. Such float-and-sink tests form an important element of the total program by providing the basic data for determining the sharpness of the separation achieved.

Results from an extensive Bureau of Mines investigation of coal washability (e.g., float-sink tests) show that the organic sulfur and the effects of crushing vary widely when washability of coals throughout the U.S. is examined. Higher sulfur content coals that indicate a potential to wash to a total sulfur content of approximately 1 percent are found principally in the Appalachian Region, particularly the Northern Region. Figures 8.1 through 8.5 are a sampling of the washing characteristics of several of the more attractive coals in the Northern Appalachian and Eastern Interior Regions. The curves show sulfur reduction potential in relation to 3/8 in. and 1-1/2 in. top sizes and percent (weight) yield. The percent ash at indicated yield values and the organic sulfur levels are also indicated. As shown by the figures, these coals have substantial total sulfur reductions at a 90 percent or greater (weight) yield.

Increased interest in the utilization of coal, together with the realization that substantial quantities of Interior and Appalachian coals exhibit reasonable sulfur reductions on physical cleaning, has led to considerations of physical cleaning as a total or partial step in meeting environmental standards. One approach would be to clean selected coals that provide for reasonable sulfur reductions at reasonable cost followed by a minimal, economically attractive, flue-gas desulfurization system.

This concept of physical coal cleaning combined with flue-gas desulfurization is not new. For some time there have been discussions, speculations, and some very preliminary assessments addressing the possible benefits of physical coal desulfurization followed by flue-gas desulfurization. Past opinions, based on a general appreciation of some of the cost and benefit factors associated with such an approach, have led to the expressed belief that, in many instances, economic advantage could be attained. Even so, contradictory expressions are also evident.

The Bureau of Mines, therefore, decided to proceed with an analytical assessment that would more fully define the potential economics of physical coal desulfurization followed by flue-gas desulfurization as a means for increasing the utilization potential of some of our higher sulfur content coals. This paper provides an overview of that study performed for the U.S. Bureau of Mines by the Hoffman-Muntner Corporation. The study approach, based on reasonable and realistic study parameters, examined the economics of physical cleaning followed by flue-gas desulfurization as a means of satisfying environmental, sulfur-related emission standards. Economic associated parameters were based on current and past conditions. It should be noted that industry economic factors exhibit considerable spread. In this regard, study values chosen tended to provide conservative (i.e., least attractive) economics of physical cleaning followed by flue-gas desulfurization.

GENERAL APPROACH

Some coals can be physically cleaned to a total sulfur content level consistent with governing environmental standards. In some cases, this can be accomplished at reasonable cost and reasonable loss in total heat content value (i.e., on a per ton basis). Even though many coals can be cleaned to provide a substantial reduction in total sulfur, the beneficiated coal product is often too high in sulfur to meet environmental requirements. In many cases, the beneficiated coal is close enough to meeting standards that a small amount of SO_2 emission control would enable the coal to be used in an environmentally acceptable fashion. The required degree of SO_2 emission control can often be achieved by employing a low-removal-efficiency, SO_2, flue-gas desulfurization system or a highly efficient flue-gas desulfurization system treating only a portion of the total stack gas.

The relationship between flue-gas desulfurization (FGD) cleaning efficiency, portion of the total gas cleaned, and the normalized emission level is defined by the following:

$$y = 1 - nx$$

where:

y = total SO_2 emitted with FGD/total SO_2 emitted without FGD

n = flue gas desulfurization efficiency of treated portion of flue gas (expressed as a decimal)

x = decimal proportion of flue gas cleaned.

Therefore, for a given cleaning efficiency, the relationship between portion of gas cleaned and the normalized emitted SO_2 emission level (i.e., y) is defined by a straight line. In a similar manner, the relationship between portion of gas cleaned and the normalized amount removed is also described by a straight line (see Figure 8.6).

Given the raw coal ash, Btu, and sulfur characteristics; the related float-sink test data and transportation economics; and the SO_2 emission limitations, economic assessments of coal cleaning (to reduce sulfur and ash) followed by SO_2 cleanup can be addressed. The addressed economics would cover the various identified costs and benefits directly related to coal beneficiation. These benefits (other than those associated with environmental satisfaction) mainly result from lower coal ash and sulfur content via cleaning. The cleaning cost/benefit assessments can then be modified to encompass the SO_2 cleanup process.

The overall economics will be sensitive to the achieved ash and sulfur reductions, the resulting coal yield, and cost of physical cleaning. The amount of physical desulfurization will relate to the level of sulfur prior to combustion and will therefore help define the required degree of flue-gas desulfurization. Generally, for a given coal top size, coal exhibits a breakpoint in attainable ash and sulfur reduction as a function of yield. If coal benefication has any attractiveness for a given use situation, the optimum coal benefication level would be that level where a substantial change in ash and sulfur reduction potential occurs vs coal yield (Figure 8.7).

ECONOMIC ANALYSIS

The net cost per ton of coal burned for meeting environmental standards through combined physical coal cleaning followed by stack gas cleaning is dependent on numerous factors. These can be divided into cost and benefit factors. The sum of coal cleaning cost factors and stack-gas cleaning cost factors less benefits derived through the use of cleaned coal defines the economics of the concept.

The cost associated with providing a ton of coal physically cleaned at the mine is the sum of the cost factors given in Figure 8.8. The cost associated with cleaning the flue gas from a ton of coal burned is the sum of the factors given in Figure 8.9. The economic benefit associated with the use of desulfurized coal is the sum of the factors given in Figure 8.10.

For the study, industry supplied values were employed. The analyses were based in part on the following:

- The considered coals were those for which the Bureau of Mines performed float-sink analyses. Bureau of Mines reported ash and sulfur levels vs top size and yield values were used.
- The top size coal considered was 3/8 inch.
- Economic assessments were based on a range of raw coal selling prices and a range of mining costs for a ton of coal.
- A coal cleaning plant cost of $18,000 per ton hour input capacity for plants of 500 tons per hour or greater.
- A coal cleaning plant financed by a 15-year equal payment self-liquidating loan.
- A coal cleaning plant utilization factor of 38.5 percent.
- A coal cleaning plant tax and insurance level equal to 2 percent of the initial investment.
- A power plant ash disposal cost of $4 per ton.
- A power plant coal grinding cost of $0.50 per ton.
- Annual stack-gas scrubber capital charges that are based on the original investment and the remaining boiler life.
- Stack-gas scrubber size/cost values based on recent EPA funded studies and a size/cost exponential relationship of 0.8.
- Flue-gas cleaning operating labor costs that are invariant to plant size (i.e., there is a minimum practical labor level).
- General power plant locations that are consistent with actual conditions.
- Coal producing areas serving assumed user locations consistent with past patterns.
- Coal transportation parameters consistent with economical coal delivery (to insure conservative economic relationships).
- An assumed power plant boiler size of 500 MW with a utilization of 7000 hours for a new plant and 5000 hours for a 10-year-old plant.
- Stack-gas scrubber systems of the minimum "practical" sizes necessary to meet standards.

STUDY FINDINGS

The economic analyses covering physical desulfurization of coal followed by flue-gas desulfurization and flue-gas desulfurization used alone for selected coal/user combinations indicate that economic generalizations must be approached with caution. The range of variables are such that each case must be individually assessed. The overall study findings were quantified in terms of 50 case studies.

The potential attractiveness of combined physical cleaning followed by stack gas cleaning is highly dependent on both the emission standard and the achievable reduction in coal ash and sulfur content upon physical cleaning. Specifically, the potential attractiveness depends on the ability to reduce the flue-gas desulfurization requirement by economically removing sulfur from coal through physical desulfurization and from other economic benefits accruing from shipping and burning coal of reduced ash and sulfur contents. The reduction in ash content provides for a higher Btu content coal, thereby providing benefits such as reduced effective transportation costs and lower ash disposal costs to the user. An examination of the overall economic factors indicate it is economically preferable to clean coal at the mine rather than at the user location.

The various cost and benefit factors that were considered in the 50 case studies are (as previously indicated) given in Figures 8.8 through 8.10. Every attempt was made to insure a conservative analysis. The intent was to understate rather than overstate economic benefits. In this regard, attempts were made to employ cost related factors such as transportation, ash disposal, grinding, cleaning plant utilization, cleaning plant operation and maintenance that would tend toward conservative economic findings. As indicated, the case study results (Figures 8.11 through 8.23) display a range of values for the cost of meeting emission standards for combined use of physical desulfurization followed by stack-gas desulfurization. The spread provided resulted from considerations of a range of prices for both the mine operator's cost to provide a ton of raw coal to the coal cleaning plant and a range of F.O.B. mine raw coal prices.

To further insure for reasonable comparisons of the cost to meet SO_2 emission standards with flue-gas desulfurization as compared to combined use of physical cleaning followed by flue-gas desulfurization, the following guidelines were used.

(1) The same coal was considered for both cases.

(2) The amount of flue-gas desulfurization considered was only that needed (with a small margin) to achieve the emission standard.

(3) Where a range of economic values exist (e.g., coal transportation cost) only those values that would provide conservative savings were used.

The overall analyses are too extensive to be fully covered by this paper. Even so, an indication of the analytic approach for Case Number 5 is as follows.

The total differential production cost to the mine operator to provide a ton of clean coal ranged between \$3.11 and \$3.55 per ton of coal. This value as a function of the mine operator's cost per ton of raw coal is due to (1) value of coal loss during cleaning, (2) cleaning plant amortization cost, (3) cleaning plant operation and maintenance cost, and (4) cleaning plant tax and insurance burden.

The total benefit from coal cleaning ranged between \$1.97 and \$2.16 per ton. This value, as a function of the F.O.B. mine raw coal selling price, is composed of (1) added coal value due to higher heat content, (2) saving in effective transportation cost, (3) saving in ash disposal cost, (4) saving in coal grinding cost, and (5) saving in user boiler maintenance cost.

The stack-gas cost factors, as based on cleaning 21 percent of flue gas, amounted to \$1.81 per ton of coal burned. The considered cost factors were (1) flue-gas system capital contribution, (2) fuel and electricity, (3) maintenance, (4) limestone, (5) fixation chemicals, (6) operating labor, (7) supplies, and (8) overhead. The overall net total cost to meet emission standards equated to a value between \$0.10 and \$0.12 per million Btu burned.

It should be noted that for the analysis, coals were essentially selected at random. The principal criteria being that (1) upon physical desulfurization, they did not display overly attractive sulfur reduction potentials, and (2) they indicated reasonable sulfur reduction levels with a top size of 3/8 inch or larger with attractive weight yields.

The overall study findings, covering the combined use of physical cleaning followed by flue-gas desulfurization, indicated a savings of 2 percent to 112 percent, as compared to flue-gas desulfurization alone. The results were even more impressive for existing plants, where study assessments indicated an 11 percent to 140 percent savings for physical cleaning followed by flue-gas desulfurization as compared to FGD alone.

CONCLUSIONS

Available data indicates that many coals can be beneficiated to remove ash and sulfur at an attractive net cost. These coals, with reduced ash and sulfur content levels, are often not too far removed from the sulfur content levels required to meet environmental standards in some areas that they traditionally serve.

When coal can be physically cleaned to a level not too far removed from that required to meet emission standards, flue-gas desulfurization treating only a portion of the flue gas would provide for environmental satisfaction. In many cases, the (net) cost of physical desulfurization followed by flue-gas desulfurization is substantially less than that through flue-gas desulfurization alone. This is due to the net economics associated with physical cleaning coal combined with the substantially lower flue-gas desulfurization costs. In essence, the net cost (i.e., costs less benefits) associated with physical desulfurization would be less than the additional cost if flue-gas desulfurization was used alone.

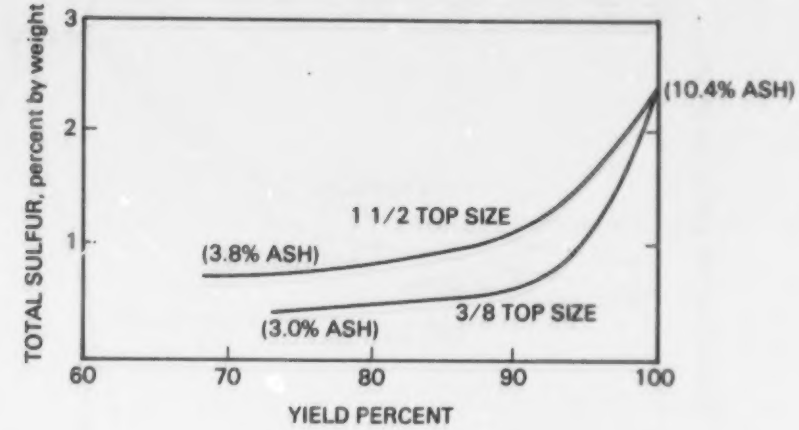
For existing power plants, flue-gas desulfurization systems are especially expensive due to both higher capital costs and to the shorter economic lives of the systems. In many such cases, the combined use of physical desulfurization followed by flue-gas desulfurization can be especially attractive.

The case studies provided indicate that for many potential situations the economic advantage of a combined approach is quite significant. Key elements in this economic advantage relate to: (1) the availability of coals capable of significant reductions in ash and sulfur at reasonable weight yields, and (2) a beneficiated coal sulfur level that is compatible with significantly less than full scale scrubbing requirements. Even so, the range of variables is such that each coal source/user combination must be individually assessed. The results can be unrealistically weighted to indicate excessively attractive economics by employing unrealistic factors (e.g., shipping coal further than is normally warranted).

The assessments imply that the attractiveness of many of our medium- to high-sulfur coals can be enhanced by cleaning to provide an assured supply of coal that could be used with more economic flue-gas desulfurization. This is true for many as-mined medium-sulfur coals and some higher sulfur coals that could serve areas with less restrictive environmental standards.

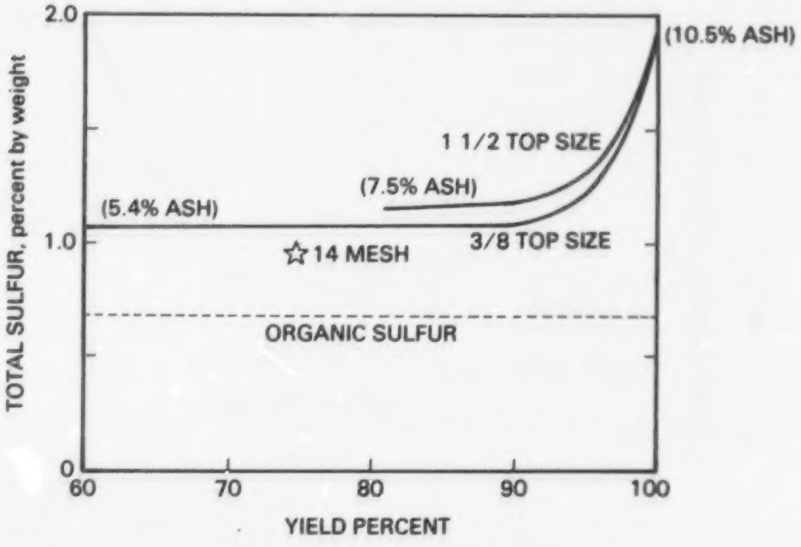
ACKNOWLEDGMENT

The authors wish to gratefully acknowledge the assistance and consultation provided by Mr. T. K. Janes of the United States Environmental Protection Agency.



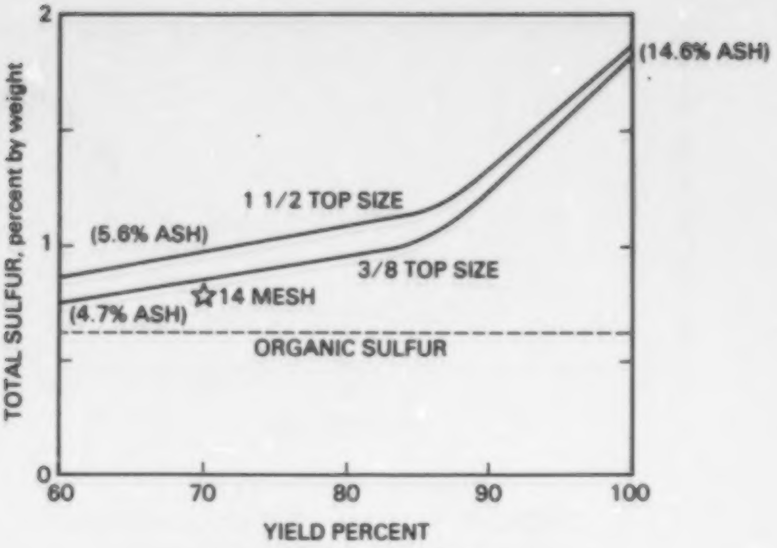
WASHABILITY TEST
MIDDLE KITTANNING COALBED:
COLUMBIANA COUNTY, OHIO

FIGURE 8.1



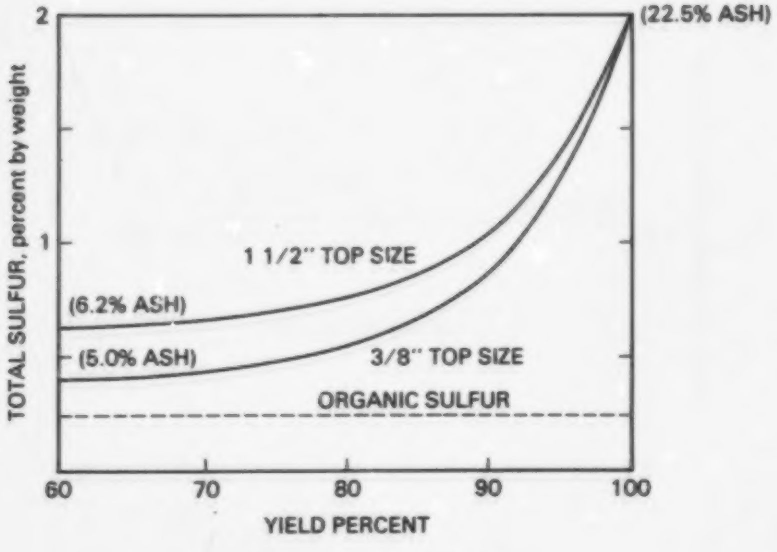
WASHABILITY TEST
COALBED NO.VII — SULLIVAN COUNTY, INDIANA

FIGURE 8.2



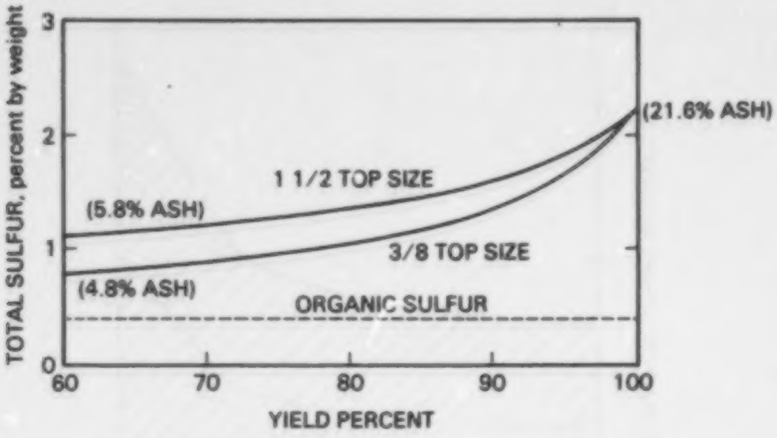
WASHABILITY TEST
LOWER KITTANNING COALBED:
GARRETT COUNTY, MARYLAND

FIGURE 8.3



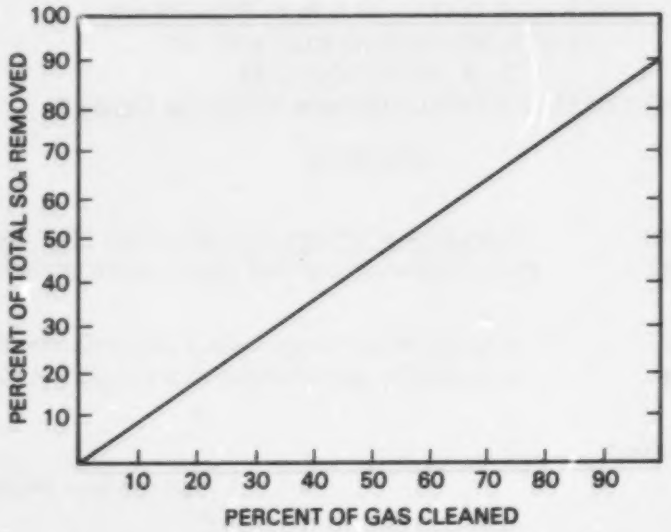
WASHABILITY TEST
UPPER FREEPORT COALBED:
ALLEGHENY COUNTY, PA

FIGURE 8.4



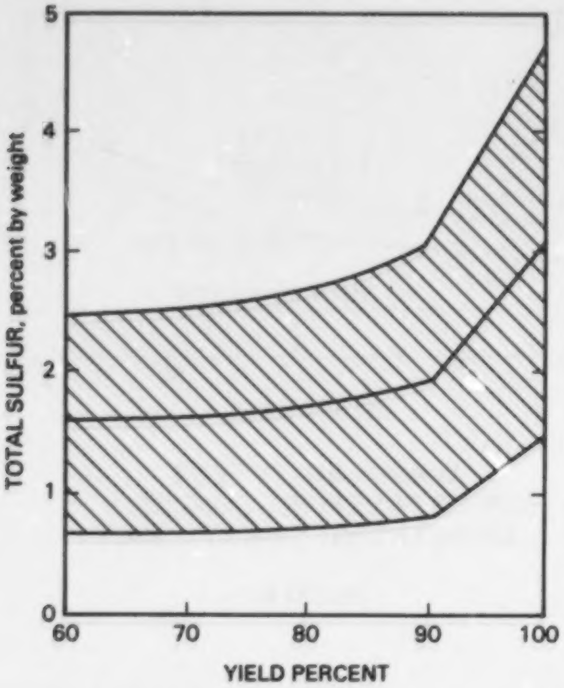
WASHABILITY TEST
UPPER FREEPORT COALBED:
ARMSTRONG COUNTY, PA.

FIGURE 8.5



SO$_x$ CHARACTERISTICS AFTER CLEANING
A PORTION OF TOTAL STACK GAS
SO$_x$ REMOVAL EFFICIENCY — 90%
(FOR TREATED GAS)

FIGURE 8.6



AVERAGE TOTAL SULFUR CONTENT,
± STANDARD DEVIATION AT
3/8-INCH TOP SIZE,
NORTHERN APPALACHIAN REGION COALS

FIGURE 8.7

$$\text{AMORTIZATION OF CLEANING PLANT} = \frac{\text{YEARLY AMORTIZATION COST PER TON HR. INPUT CAPACITY}}{\text{8760 X UTILIZATION (DECIMAL VALUE) X YIELD (DECIMAL VALUE)}}$$

OPERATION & MAINTENANCE — • BASED ON HISTORICAL DATA • IDENTIFICATION OF COST COMPONENTS • COST ESCALATION FACTORS • PLANT YIELD

$$\text{VALUE OF ``ADDITIONAL'' RAW COAL} = \text{PER TON RAW COAL VALUE} \left(\frac{1}{\text{YIELD (DECIMAL VALUE)}} - 1 \right)$$

$$\text{TAX \& INSURANCE} = \frac{\text{PLANT COST PER TON HR. INPUT CAPACITY X RATE}}{\text{8760 X UTILIZATION (DECIMAL VALUE) X YIELD (DECIMAL VALUE)}}$$

COST FACTORS PER TON CLEANED COAL

FIGURE 8.8

CAPITAL CONTRIBUTION
FIXATION CHEMICALS
FUEL AND ELECTRICITY COST
LIMESTONE
MAINTENANCE (LABOR & MATERIALS)
OPERATING LABOR
OVERHEAD
SUPPLIES

FLUE GAS CLEANING COST COMPONENTS

FIGURE 8.9

INCREASED HEAT = F.O.B. RAW COAL COST PER TON • $\frac{X}{1+X}$

TRANSPORTATION SAVING = TRANSPORTATION COST PER TON • $\frac{X}{1+X}$

ASH DISPOSAL COST SAVING = COST TO DISPOSE OF TON OF ASH • X (1 + X)

GRINDING COST SAVING = COST TO GRIND A TON OF COAL • $\frac{X}{1+X}$

MAINTENANCE SAVING – BASED ON TVA COLLECTED DATA

X = (DECIMAL INCREASE IN HEAT CONTENT DUE TO CLEANING)

BENEFIT FACTORS PER TON CLEANED COAL

FIGURE 8.10

CASE NUMBERS: 1, 2, 3, and 4

Destination (coal use area): Knoxville (Clinton), Tennessee

Coal Source Area: Sullivan County, Indiana

Coalbed: No. VII

Coal District: No. 11

Raw Coal: 10.5% Ash; 1.87% Sulfur

Clean Coal: 7.3% Ash; 1.11% Sulfur

Case Number 1: New plant with combined use of physical cleaning followed by stack gas scrubbing.

Emission standard 1.2 lb $SO_2/10^6$ Btu.

Total cost to meet emission standard: \$0.15-\$0.17/10^6 Btu.

Case Number 2: New plant with sulfur cleanup exclusively by stack gas scrubbing.

Emission standard 1.2 lb $SO_2/10^6$ Btu.

Total cost to meet emission standard: \$0.19/10^6 Btu.

Case Number 3: Existing plant with combined use of physical cleaning followed by stack gas scrubbing.

Emission standard 1.2 lb $SO_2/10^6$ Btu.

Total cost to meet emission standard: \$0.23-\$0.25/10^6 Btu.

Case Number 4: Existing plant with sulfur cleanup exclusively by stack gas scrubbing.

Emission standard 1.2 lb $SO_2/10^6$ Btu.

Total cost to meet emission standard: \$0.32/10^6 Btu.

SUMMARIZATION OF CASE RESULTS

FIGURE 8.11

CASE NUMBERS: 5, 6, 7, and 8

Destination (coal use area): Tonawanda (Buffalo), New York

Coal Source Area: Cambria County, Pennsylvania

Coalbed: Lower Freeport

Coal District: No. 1

Raw Coal: 11.4% Ash; 2.4% Sulfur

Clean Coal:6.7% Ash; 1.01% Sulfur

Case Number 5:	New plant with combined use of physical cleaning followed by stack gas scrubbing. Emission standard 1.2 lb $SO_2/10^6$ Btu. Total cost to meet emission standard: \$0.10-\$0.12/10^6 Btu.
Case Number 6:	New plant with sulfur cleanup exclusively by stack gas scrubbing. Emission standard 1.2 lb $SO_2/10^6$ Btu. Total cost to meet emission standard: \$0.22/10^6 Btu.
Case Number 7:	Existing plant with combined use of physical cleaning followed by stack gas scrubbing. Emission standard 1.4 lb $SO_2/10^6$ Btu. Total cost to meet emission standard: \$0.06-\$0.09/10^6 Btu.
Case Number 8:	Existing plant with sulfur cleanup exclusively by stack gas scrubbing. Emission standard 1.4 lb $SO_2/10^6$ Btu. Total cost to meet emission standard: \$0.15/10^6 Btu.

SUMMARIZATION OF CASE RESULTS

FIGURE 8.12

CASE NUMBERS: 9, 10, 11, and 12

Destination (coal use area): Essexville (Saginaw), Michigan

Coal Source Area: Harrison County, Ohio

Coalbed: Lower Freeport

Coal District: No. 4

Raw Coal: 10.4% Ash; 2.30% Sulfur

Clean Coal:4.8% Ash; 1.26% Sulfur

Case Number 9:	New plant with combined use of physical cleaning followed by stack gas scrubbing. Emission standard 1.2 lb $SO_2/10^6$ Btu. Total cost to meet emission standard: \$0.12-\$0.14/10^6 Btu.
Case Number 10:	New plant with sulfur cleanup exclusively by stack gas scrubbing. Emission standard 1.2 lb $SO_2/10^6$ Btu. Total cost to meet emission standard: \$0.21/10^6 Btu.
Case Number 11:	Existing plant with combined use of physical cleaning followed by stack gas scrubbing. Emission standard 1.6 lb $SO_2/10^6$ Btu. Total cost to meet emission standard: \$0.11-\$0.14/10^6 Btu.
Case Number 12:	Existing plant with sulfur cleanup exclusively by stack gas scrubbing. Emission standard 1.6 lb $SO_2/10^6$ Btu. Total cost to meet emission standard: \$0.30/10^6 Btu.

SUMMARIZATION OF CASE RESULTS

FIGURE 8.13

CASE NUMBERS: 13, 14, 15, and 16

Destination (coal use area): Boston, Massachusetts

Coal Source Area: Clearfield County, Pennsylvania

Coalbed: Upper Kittanning

Coal District: No. 1

Raw Coal: 9.3% Ash; 0.85% Sulfur

Clean Coal: 7.0% Ash; 0.45% Sulfur

Case Number 13: New plant with combined use of physical cleaning followed by stack gas scrubbing.

Emission standard 0.28 lb of sulfur/10^6 Btu.

Total cost to meet emission standard: \$0.12-\$0.14/10^6 Btu.

Case Number 14: New plant with sulfur cleanup exclusively by stack gas scrubbing.

Emission standard 0.28 lb of sulfur/10^6 Btu.

Total cost to meet emission standard: \$0.17/10^6 Btu.

Case Number 15: Existing plant with combined use of physical cleaning followed by stack gas scrubbing.

Emission standard 0.28 lb of sulfur/10^6 Btu.

Total cost to meet emission standard: \$0.17-\$0.19/10^6 Btu.

Case Number 16: Existing plant with sulfur cleanup exclusively by stack gas scrubbing.

Emission standard 0.28 lb of sulfur/10^6 Btu.

Total cost to meet emission standard: \$0.29/10^6 Btu.

SUMMARIZATION OF CASE RESULTS

FIGURE 8.14

CASE NUMBERS: 17, 18, 19, and 20

Destination (coal use area): Grand Rapids, Michigan

Coal Source Area: Preston County, West Virginia

Coalbed: Upper Freeport

Coal District: No. 3

Raw Coal: 18.5% Ash; 2.24% Sulfur

Clean Coal: 11.9% Ash; 1.25% Sulfur

Case Number 17: New plant with combined use of physical cleaning followed by stack gas scrubbing.

Emission standard 1.6 lb $SO_2/10^6$ Btu.

Total cost to meet emission standard: \$0.07-\$0.10/10^6 Btu.

Case Number 18: New plant with sulfur cleanup exclusively by stack gas scrubbing.

Emission standard 1.6 lb $SO_2/10^6$ Btu.

Total cost to meet emission standard: \$0.18/10^6 Btu.

Case Number 19: Existing plant with combined use of physical cleaning followed by stack gas scrubbing.

Emission standard 1.6 lb $SO_2/10^6$ Btu.

Total cost to meet emission standard: \$0.12-\$0.14/10^6 Btu.

Case Number 20: Existing plant with sulfur cleanup exclusively by stack gas scrubbing.

Emission standard 1.6 lb $SO_2/10^6$ Btu.

Total cost to meet emission standard: \$0.30/10^6 Btu.

SUMMARIZATION OF CASE RESULTS

FIGURE 8.15

CASE NUMBERS: 21, 22, 23, and 24

Destination (coal use area): Springfield, Massachusetts

Coal Source Area: Armstrong County, Pennsylvania

Coalbed: Upper Freeport

Coal District: No. 2

Raw Coal: 13.0% Ash; 2.53% Sulfur

Clean Coal: 7.2% Ash; 1.09% Sulfur

Case Number 21: New plant with combined use of physical cleaning followed by stack gas scrubbing.

Emission standard 0.55 lb of sulfur/10^6 Btu.

Total cost to meet emission standard: \$0.11-\$0.13/10^6 Btu.

Case Number 22: New plant with sulfur cleanup exclusively by stack gas scrubbing.

Emission standard 0.55 lb of sulfur/10^6 Btu.

Total cost to meet emission standard: \$0.23/10^6 Btu.

Case Number 23: Existing plant with combined use of physical cleaning followed by stack gas scrubbing.

Emission standard 0.55 lb of sulfur/10^6 Btu.

Total cost to meet emission standard: \$0.18-\$0.21/10^6 Btu.

Case Number 24: Existing plant with sulfur cleanup exclusively by stack gas scrubbing.

Emission standard 0.55 lb of sulfur/10^6 Btu.

Total cost to meet emission standard: \$0.38/10^6 Btu.

SUMMARIZATION OF CASE RESULTS

FIGURE 8.16

CASE NUMBERS: 25, 26, 27, and 28

Destination (coal use area): Lansing, Michigan

Coal Source Area: Jefferson County, Ohio

Coalbed: Pittsburgh

Coal District: No. 4

Raw Coal: 9.8% Ash; 2.82% Sulfur

Clean Coal: 6.0% Ash; 2.03% Sulfur

Case Number 25: New plant with combined use of physical cleaning followed by stack gas scrubbing.

Emission standard 1.6 lb $SO_2/10^6$ Btu.

Total cost to meet emission standard: \$0.19-\$0.22/10^6 Btu.

Case Number 26: New plant with sulfur cleanup exclusively by stack gas scrubbing.

Emission standard 1.6 lb $SO_2/10^6$ Btu.

Total cost to meet emission standard: \$0.22/10^6 Btu.

Case Number 27: Existing plant with combined use of physical cleaning followed by stack gas scrubbing.

Emission standard 1.6 lb $SO_2/10^6$ Btu.

Total cost to meet emission standard: \$0.30-\$0.32/10^6 Btu.

Case Number 28: Existing plant with sulfur cleanup exclusively by stack gas scrubbing.

Emission standard 1.6 lb $SO_2/10^6$ Btu.

Total cost to meet emission standard: \$0.35/10^6 Btu.

SUMMARIZATION OF CASE RESULTS

FIGURE 8.17

CASE NUMBERS: 29, 30, 31, and 32

Destination (coal use area): Nashville (Gallatin), Tennessee

Coal Source Area: Vigo County, Indiana

Coalbed: No. VII

Coal District: No. 11

Raw Coal: 12.0% Ash; 1.54% Sulfur

Clean Coal: 7.7% Ash; 0.90% Sulfur

Case Number 29:	New plant with combined use of physical cleaning followed by stack gas scrubbing. Emission standard 1.2 lb $SO_2/10^6$ Btu. Total cost to meet emission standard: \$0.11-\$0.13/10^6 Btu.
Case Number 30:	New plant with sulfur cleanup exclusively by stack gas scrubbing. Emission standard 1.2 lb $SO_2/10^6$ Btu. Total cost to meet emission standard: \$0.16/10^6 Btu.
Case Number 31:	Existing plant with combined use of physical cleaning followed by stack gas scrubbing. Emission standard 1.2 lb $SO_2/10^6$ Btu. Total cost to meet emission standard: \$0.16-\$0.18/10^6 Btu.
Case Number 32:	Existing plant with sulfur cleanup exclusively by stack gas scrubbing. Emission standard 1.2 lb $SO_2/10^6$ Btu. Total cost to meet emission standard: \$0.28/10^6 Btu.

SUMMARIZATION OF CASE RESULTS

FIGURE 8.18

CASE NUMBERS: 33, 34, 35, and 36

Destination (coal use area): Burlington, New Jersey

Coal Source Area: Garrett County, Maryland

Coalbed: Upper Freeport

Coal District: No. 1

Raw Coal: 13.8% Ash; 2.37% Sulfur

Clean Coal: 8.8% Ash; 1.6% Sulfur

Case Number 33: New plant with combined use of physical cleaning followed by stack gas scrubbing.

Emission standard 0.30 lb $SO_2/10^6$ Btu.

This coal will not meet emission standards for New Plants in the State of New Jersey even with combined physical and stack gas cleaning.

Case Number 34: New plant with sulfur cleanup exclusively by stack gas scrubbing.

Emission standard 0.30 lb $SO_2/10^6$ Btu.

This coal will not meet emission standards for New Plants in the State of New Jersey using stack gas scrubbing.

Case Number 35: Existing plant with combined use of physical cleaning followed by stack gas scrubbing.

Emission standard 1 percent sulfur by weight.

Total cost to meet emission standard: \$0.23-\$0.25/10^6 Btu.

Case Number 36: Existing plant with sulfur cleanup exclusively by stack gas scrubbing.

Emission standard 1 percent sulfur by weight.

Total cost to meet emission standard: \$0.32/10^6 Btu.

SUMMARIZATION OF CASE RESULTS

FIGURE 8.19

CASE NUMBERS: 37, 38, 39, and 40

Destination (coal use area): Milwaukee, Wisconsin

Coal Source Area: Franklin County, Illinois

Coalbed: No. 6

Coal District: No. 10

Raw Coal: 14.8% Ash; 1.12% Sulfur

Clean Coal: 7.1% Ash; 0.95% Sulfur

Case Number 37: New plant with combined use of physical cleaning followed by stack gas scrubbing.

Emission standard 1.2 lb $SO_2/10^6$ Btu.

Total cost to meet emission standard: \$0.07-\$0.10/10^6 Btu.

Case Number 38: New plant with sulfur cleanup exclusively by stack gas scrubbing.

Emission standard 1.2 lb $SO_2/10^6$ Btu.

Total cost to meet emission standard: \$0.12/10^6 Btu.

Case Number 39: Existing plant with combined use of physical cleaning followed by stack gas scrubbing.

Emission standard 1.2 lb $SO_2/10^6$ Btu.

Total cost to meet emission standard: \$0.12-\$0.15/10^6 Btu.

Case Number 40: Existing plant with sulfur cleanup exclusively by stack gas scrubbing.

Emission standard 1.2 lb $SO_2/10^6$ Btu.

Total cost to meet emission standard: \$0.20/10^6 Btu.

SUMMARIZATION OF CASE RESULTS

FIGURE 8.20

CASE NUMBERS: 41, 42, 43, and 44

Destination (coal use area): Concord, New Hampshire

Coal Source Area: Greene County, Pennsylvania

Coalbed: Sewickley

Coal District: No. 2

Raw Coal: 11.4% Ash; 3.45% Sulfur

Clean Coal: 8.1% Ash; 2.20% Sulfur

Case Number 41: New plant with combined use of physical cleaning followed by stack gas scrubbing.

Emission standard 1.5 lb of sulfur/10^6 Btu.

Total cost to meet emission standard: \$0.09-\$0.11/10^6 Btu.

Case Number 42: New plant with sulfur cleanup exclusively by stack gas scrubbing.

Emission standard 1.5 lb of sulfur/10^6 Btu.

Total cost to meet emission standard: \$0.17/10^6 Btu.

Case Number 43: Existing plant with combined use of physical cleaning followed by stack gas scrubbing.

Emission standard 1.5 lb of sulfur/10^6 Btu.

Total cost to meet emission standard: \$0.12-\$0.14/10^6 Btu.

Case Number 44: Existing plant with sulfur cleanup exclusively by stack gas scrubbing.

Emission standard 1.5 lb of sulfur/10^6 Btu.

Total cost to meet emission standard: \$0.28/10^6 Btu.

SUMMARIZATION OF CASE RESULTS

FIGURE 8.21

CASE NUMBERS: 45 and 46

Destination (coal use area): Concord, New Hampshire

Coal Source Area: Greene County, Pennsylvania

Coalbed: Sewickley

Coal District: No. 2

Raw Coal: 11.4% Ash; 3.45% Sulfur

Clean Coal: 8.1% Ash; 2.20% Sulfur

Case Number 45: New plant with combined use of physical cleaning followed by stack gas scrubbing.

Emission standard 1.2 lb $SO_2/10^6$ Btu (Projected Standard).

Total cost to meet emission standard: $0.25-$0.28/10^6 Btu.

Case Number 46: New plant with sulfur cleanup exclusively by stack gas scrubbing.

Emission standard 1.2 lb $SO_2/10^6$ Btu (Projected Standard).

Total cost to meet emission standard: $0.27/$10^6$ Btu.

Case

SUMMARIZATION OF CASE RESULTS

FIGURE 8.22

CASE NUMBERS: 47, 48, 49, and 50

Destination (coal use area): Dickerson (Montgomery County), Maryland

Coal Source Area: Marion County, West Virginia

Coalbed: Pittsburgh

Coal District: No. 3

Raw Coal: 11.0% Ash; 3.80% Sulfur

Clean Coal: 5.9% Ash; 2.16% Sulfur

Case Number 47: New plant with combined use of physical cleaning followed by stack gas scrubbing.

Emission standard 1 percent sulfur by weight.

Total cost to meet emission standard: \$0.20-\$0.23/10^6 Btu.

Case Number 48: New plant with sulfur cleanup exclusively by stack gas scrubbing.

Emission standard 1 percent sulfur by weight.

Total cost to meet emission standard: \$0.27/10^6 Btu.

Case Number 49: Existing plant with combined use of physical cleaning followed by stack gas scrubbing.

Emission standard 1 percent sulfur by weight.

Total cost to meet emission standard: \$0.32-\$0.34/10^6 Btu.

Case Number 50: Existing plant with sulfur cleanup exclusively by stack gas scrubbing.

Emission standard 1 percent sulfur by weight.

Total cost to meet emission standard: \$0.43/10^6 Btu.

SUMMARIZATION OF CASE RESULTS

FIGURE 8.23

THE EPA REGION IV TVA STUDY

Gerald A. Isaacs
PEDCo Environmental, Inc.

INTRODUCTION

Although coal cleaning is not a new technology, the concept of using a coal cleaning plant to remove pyritic sulfur from coal in order to permit a boiler to meet applicable SO_2 emission regulations is relatively new. The potential implementation of this concept is described briefly in this paper, and example data are presented which show that certain coals may be amenable to cleaning within the SO_2 constraints of a particular utility system. It is believed that similar potential applications may exist for other utility systems that are faced with the need to comply with SO_2 emission restrictions.

In 1975, Region IV of the U.S. Environmental Protection Agency contracted with PEDCo Environmental, Inc. to investigate the washability potential of several TVA contract coals and to determine a feasible overall strategy whereby TVA might meet appropriate SO_2 emission restrictions. Some of the data generated in that study are presented in this paper to show that coal can be cleaned and used to meet SO_2 regulations. The examples cited do not necessarily reflect the best use of these coals within the TVA system and are presented for illustrative purposes only. The best use of these coals would have to be determined by TVA in conjunction with the total TVA coal supply and the firing requirements at all the plants. Although the developed strategy also included the use of flue-gas desulfurization (FGD) systems, this paper describes only the coal cleaning and coal redistribution aspects of the strategy.

STRUCTURE OF THE PROBLEM

The fossil-fired system of the Tennessee Valley Authority (TVA) is typical of many U.S. utility systems in that it consists of several separate coal-fired power plants that are located within a broad geographical area. Historically, coal to supply these plants has been obtained by contract from several sources, small and large, generally located within, or close to, the geographical area served by the TVA. Current regulations, which limit SO_2 emissions from each of these power plants, place significant restrictions on the continued utilization of these traditional coal supplies. These SO_2 emission limiting regulations have been prescribed by the various states where the plants are located and are incorporated in individual state implementation plans that have been approved to meet Federal EPA requirements. The most restrictive SO_2 regulations, equal to Federal new source performance standards, 1.2 lb $SO_2/10^6$ Btu, are applicable at four plants; i.e., Johnsonville, Kingston, Shawnee, and Widows Creek. The least restrictive regulation, 5.2 lb $SO_2/10^6$ Btu, is applicable at the Paradise plant. Of the seven remaining plants, five are subject to a regulation of 4.0 lb $SO_2/10^6$ Btu, and two are limited to 5.0 lb $SO_2/10^6$ Btu. Figure 9.1 shows the SO_2 regulations and the anticipated 1980 fuel requirements for each of the twelve plants. The total yearly fuel requirement, 172.5×10^{11} Btu, is equivalent to about 40 million tons of coal.

Two of the five plants that are subject to a 4.0 lb $SO_2/10^6$ Btu regulation, Allen and Paradise, are equipped with cyclone boilers that require coal that has a low ash-fusion temperature. Wet-bottom furnaces at Watts Bar require a similar coal. This type coal cannot generally be burned at the other nine power plants, and most of the coal for those nine plants cannot be burned at Allen, Paradise, and Watts Bar. Although many coals are now interchanged freely between plants, the SO_2 regulations will tend to limit this flexibility in the future. A coal that produces 5.0 lb $SO_2/10^6$ Btu cannot be burned at any of the nine plants where the regulation is more restrictive, except where FGD systems are installed to accommodate high-sulfur coal. Any low-sulfur coal for the four 1.2 lb $SO_2/10^6$ Btu plants cannot generally be burned at the other eight plants, because the precipitators at those plants will not be adequate for the low-sulfur coal.

Other factors also have to be considered in arriving at an overall SO_2 control strategy. Some coal supplies have been essentially dedicated to particular power plants. For example, the coal reserves at the Camp Breckenridge mines are owned by TVA and are mined under long-term contract by Peabody, shipped overland by conveyor to barge loading facilities, and transported to the Cumberland power plant. At the Paradise power plant, coal is supplied from nearby mines by large off-highway trucks that travel on a private roadway system. It would be difficult to redistribute this coal to other TVA power plants, and it would be equally difficult to transport other coal to Paradise even in the absence of ash-fusion considerations. Coals within the TVA system are delivered to the various plants by truck, barge, and rail, but the plants are not generally equipped to receive coal by more than one or two of these three modes of shipment. Even in cases where the power plant and coal mine are both served by rail facilities, the plant-mine combination may not be compatible. The costs of transferring coal from one railroad to another are in some cases considerably higher than if the coal were moved the same distance by a single railroad.

In brief, TVA will be faced with logistics problems that have not previously existed. Coal mines and power plants will have to be linked by compatible transportation networks, and the coal to each power plant will have to be consistent with the pollution control equipment at that plant to meet the regulations. In the face of future forced outages at any plant, TVA will not readily be able to divert contract coal to another plant at will. The diverted coal may not be consistent with the second plant's emission regulations. When coal contractors fail to meet commitments, it will generally be difficult to obtain short-term supplemental fuel that meets the emission requirements.

COMPLIANCE WITH REGULATIONS

Current technology provides only two basic methods to meet SO$_2$ emission limiting regulations at existing power plants. Either an FGD system must be used to remove part of the SO$_2$ from the boiler exhaust gas, or the coal supply to the power plant must have a sulfur content low enough to meet the standard. The complying coal option can be pursued in either of two ways. Coal with an inherent sulfur content low enough to meet the regulations can be purchased directly, or coal with a sulfur content too high to meet the regulations can be cleaned to the required level before it is burned.

The simplest solution for compliance is the direct purchase of coal that meets regulations. In cases where precipitator modifications are not necessary to accommodate the reduced coal sulfur content, little or no capital expense is incurred since neither an FGD system nor a coal cleaning plant is required. Several factors may make this selection unworkable, however, for example, large contracts for noncomplying coal that obligate the buyer may already exist. Even in cases where these contracts can be dissolved, it may not be desirable to do so if the contract coal is obtainable at a price that permits it to be cleaned or scrubbed more economically than it can be replaced with complying coals.

Coal to meet the strict regulation of 1.2 lb SO$_2$/10^6 Btu will generally require an additional capital investment to increase the size of electrostatic precipitators to accommodate the high resistivity fly ash associated with such coal. This coal may not be generally available from local sources, so transportation costs for the coal may be higher than for coal that would otherwise be purchased.

FGD systems have the capability to remove 85 to 90 percent of the SO$_2$ generated by the boiler. The principal disadvantages of these systems are high costs, operating difficulties, and sludge disposal requirements, but at the present time FGD is the only technology that has been demonstrated at an 85 percent removal level.

The sulfur removal potential for coal cleaning is on the order of 20 to 40 percent of the raw coal sulfur. Thus the applicability for the technology is limited to cases where the required degree of sulfur removal is not very high.

In some cases it appears that the annualized costs for coal cleaning and for partial application of FGD are about equal. In these cases, several points need to be considered. Our data have shown that where total annualized costs for FGD and coal cleaning are about equal, the capital cost for coal cleaning is considerably lower than for FGD. This is an incentive to choose coal cleaning over FGD especially when it is difficult to obtain capital. Another point is that coal cleaning improves a boiler fuel and is therefore expected to improve the dependability of the boiler system. On the other hand, an FGD system does not change the boiler fuel and tends to decrease the overall reliability of the boiler-FGD combination. A coal cleaning plant, in pretreating the coal, removes noncombustible impurities and sulfur. These impurities that are removed upstream from the boiler therefore do not have to be handled at the power plant. Pulverizer and ash handling requirements may be significantly reduced, and if the need for an FGD system is eliminated, the accompanying sludge disposal requirements are also eliminated. Of course this apparent advantage is only partly real. The ash and sulfur that are removed at the coal cleaning plant still require disposal, so the disposal responsibility is only transferred from the power plant operation to the coal cleaning area.

An FGD system is less specific to a coal supply than a coal cleaning plant. Therefore, in cases where long-term coal supplies have not been established, or where several different coal supplies are used at one plant, it may be more conservative to install an FGD system than a coal cleaning plant.

In summary there are two basic options for compliance. An FGD system for post combustion cleanup of the boiler exhaust gas may be installed, or complying coal may be used to insure that emission levels do not exceed prescribed regulations. Complying coal can be inherently acceptable in sulfur content, or higher sulfur coal can be cleaned to meet the SO_2 standard. There are many factors that influence a decision to adopt a particular compliance strategy, and the correct decision may require a very detailed economic analysis. Uncertainties in projections for some of the factors that go into such an analysis in some cases may lead to the selection of a conservative strategy that may not appear to be most cost-effective.

WASHABILITY DATA

In mid-1975, Region IV of the U.S. Environmental Protection Agency contracted with PEDCo Environmental, Inc. to analyze samples from several long-term TVA coal contracts in order to determine the potential to clean any of those coals to meet applicable SO_2 emission limiting regulations. Accordingly, we met with TVA and a group of coal contracts were selected for sampling. Over a period of several months TVA personnel collected a total of 22 coal samples and sent them to use for analysis. The results of some of those analyses are summarized on the following pages and are discussed briefly.

Figure 9.2 shows washability data that were generated for the coal from Old Ben Mine No. 26. This coal is presently used at Shawnee. The emission regulation at Shawnee is 1.2 lb $SO_2/10^6$ Btu. Since the raw coal has a sulfur content equivalent to 5.40 lb $SO_2/10^6$ Btu, the raw coal is not suitable for Shawnee unless an FGD system is used. The washability data show that the cleanest segment of the coal is the float 1.3 portion with a sulfur content equivalent to 2.64 lb $SO_2/10^6$ Btu. Thus, this coal cannot be physically cleaned to meet the 1.2 lb regulation at Shawnee. The coal can be cleaned, however, to meet a 4 lb regulation. By washing all the +35 mesh material at a separating density of 1.9 g/ml, and blending in all the raw −35 mesh material, a clean coal composite is calculated to have an equivalent sulfur content of 3.78 lb $SO_2/10^6$ Btu. This washed coal would have a sulfur content suitable for burning at eight of the twelve TVA plants. Nearly 99 percent of the thermal value of the raw coal would theoretically report to the clean coal fraction. In contrast, the rejected coal would contain about 1 percent of the thermal worth of the total coal, and its sulfur content would be approximately equivalent to 150 lb $SO_2/10^6$ Btu.

Figure 9.3 shows washability data for a coal sample from the Underwood mine. This coal is generally consigned to Widows Creek, but the raw coal does not meet the 1.2 lb SO_2 standard at that plant. In this case the coal can be cleaned to the 1.2 lb level. By washing the 3/8 in. × 35 mesh coal at a separating density of 1.6 g/ml, a product having a sulfur content equivalent to 1.21 lb $SO_2/10^6$ Btu is obtained. The Btu recovery for this process would only be 53 percent. If a slightly lower separating density were used in order to meet the 1.2 lb limit, the recovery would be even less, somewhere around 50 percent, indicating that an FGD system would be a more economical compliance option. However, if the coal were cleaned at 50 percent recovery for use at Widows Creek, the reject coal from the cleaning plant would have a sulfur content equivalent to 2.3 lb $SO_2/10^6$ Btu. This reject coal would still be much cleaner than most TVA coal and could be used at another plant for blending to meet regulations. The effective overall Btu recovery would then be essentially 100 percent.

Figure 9.4 shows data for coal from seam 12 of the Sinclair mine in western Kentucky. This coal is transported directly from the mine by off-highway tracks to the Paradise power plant. The regulation at Paradise is 5.2 lb $SO_2/10^6$ Btu, but the raw coal sample from this mine showed a sulfur content equivalent to 9.41 lb $SO_2/10^6$ Btu. The −35 mesh fraction is 13.22 lb $SO_2/10^6$ Btu. The coal can be cleaned to 5.2 lb $SO_2/10^6$ Btu by washing the 1-1/2 in. × 3/8 in. fraction at a separating density of 1.5 g/ml and washing the 3/8 in. × 35 mesh fraction at a density of 1.6 g/ml. The −35 mesh coal would be discarded. The total theoretical Btu recovery is 81.0 percent.

Figure 9.5 represents strip-mined coal from seam 9 of the Sinclair mine. This coal is also burned at Paradise. The raw coal sulfur content is equivalent to 6.86 lb $SO_2/10^6$ Btu. In order to clean the coal to 5.2 lb $SO_2/10^6$ million Btu the 1-1/2 in. × 3/8 in. coal could be washed at 1.8 g/ml and the 3/8 in. × 35 mesh coal could be washed at 1.9 g/ml. These two fractions and the −35 mesh coal would be blended together.

Figure 9.6 represents a coal from seam 11 of the Sinclair mine. The raw coal, having a sulfur content equivalent to 6.23 lb $SO_2/10^6$ Btu, can be cleaned to 5.09 lb $SO_2/10^6$ Btu by washing the +35 mesh fraction at 1.9 g/ml and discarding the −35 mesh fraction. Btu recovery is 93.4 percent.

Figure 9.7 contains data for a coal sample from seam 11 of the Ayrgem mine. This coal is also used at Paradise. The raw coal sulfur level is equivalent to 8.18 lb $SO_2/10^6$ Btu. The coal can be cleaned to 5.18 lb $SO_2/10^6$ Btu by washing the 1-1/2 in. × 3/8 in. fraction at 1.6 g/ml and the 3/8 in. × 35 mesh material at 1.9 g/ml. Btu recovery is 89.0 percent.

Figure 9.8 shows data for a coal sample from seam 9 of an underground portion of the Sinclair mine. The raw coal, at 6.50 lb $SO_2/10^6$ Btu, can be cleaned to 5.18 lb $SO_2/10^6$ Btu by washing the 1-1/2 in. × 3/8 in. coal at 1.8 g/ml, washing the 3/8 in. × 35 mesh coal at 1.9 g/ml, and blending in all the −35 mesh material. Btu recovery is 99.1 percent.

Figure 9.9 shows data that represents a coal sample from seam 12 of the Ayrgem mine. The raw coal, at 8.19 lb $SO_2/10^6$ Btu can be cleaned to 5.18 lb $SO_2/10^6$ Btu by washing the 1-1/2 in. × 3/8 in. coal at 1.8 g/ml and washing the 3/8 in. × 35 mesh coal at 1.6 g/ml. Btu recovery is 89.9 percent.

Each of the six coals that are used at Paradise can be cleaned to 5.2 lb $SO_2/10^6$ Btu. If it is assumed for simplification that equal portions of each coal are used, the calculated average Btu recovery is 91.9 percent. Five different cleaning schemes would have to be used to wash each coal to the 5.2 lb level. However, all of the coals could be treated in the same cleaning plant using a compromise cleaning scheme that yields 5.2 lb. $SO_2/10^6$ Btu. For example, all the +35 mesh coal could be washed at 1.8 g/ml and the −35 mesh coal could be discarded. The resulting coal would average 5.16 lb $SO_2/10^6$ Btu at 90.6 percent Btu recovery. Thus there appears to be an approximate 1.3 percent Btu penalty in using this compromise scheme on all the coals.

CONCLUSIONS

The selected examples from this study show that coal cleaning is a potential method whereby emission levels in some cases can be attained without the requirement for new coal supplies or FGD systems. These examples are not to be regarded as typical, and it cannot be concluded that coal cleaning is a general alternative to FGD. Many TVA coal samples showed little or no potential for coal cleaning and are thus not discussed in this paper. There is a moderate limit to the amount of sulfur that can be removed by a coal cleaning plant, and beyond that point FGD becomes more cost-effective than coal cleaning because refuse Btu losses from coal cleaning become excessive. In the simple analyses presented in this paper, it was assumed that −35 mesh coal was either discarded or salvaged without cleaning. Further analysis of the treatment of this coal is in order since it typically represents about 8 percent of the total Btu content of the coal. Cleaning of this fraction, even at relatively low Btu recovery, may substantially improve the economics of a coal cleaning plant, and new techniques for the cleaning of fine coal need to be developed more thoroughly.

It appears that coal cleaning may have some potential application for many utilities. The possibilities of using cleaned coal at one plant and using the refuse from that cleaning plant at another station where the SO_2 regulation is less severe or in conjunction with FGD or fluidized-bed combustion are only begining to be explored. Potential prospects for the increased use of coal cleaning as an SO_2 control method seem to justify further exploration.

State Plant	Federally Approved SO_2 Emission Limit, lb $SO_2/10^6$ Btu	Projected 1980 Coal Consumption, 10^{11} Btu/wk
Alabama		
Colbert	4.0	11.6
Widows Creek	1.2	16.2
Kentucky		
Paradise	5.2	26.6
Shawnee	1.2	17.5
Tennessee		
Allen (low ash fusion)	4.0	8.0
Bull Run	4.0	10.2
Cumberland	5.0	32.2
Gallatin	5.0	12.0
John Sevier	4.0	7.5
Johnsonville	1.2	12.4
Kingston	1.2	15.3
Watts Bar (low ash fusion)	4.0	3.0
Total		172.5

SO_2 EMISSION LIMITING REGULATIONS—TVA SYSTEM

FIGURE 9.1

Segment	Float Density	Lb $SO_2/10^6$ Btu	% of Btu's
	1-1/2 In. × 3/8 In.		
1	1.3	2.64	9.42
2	1.4	3.01	23.08
3	1.5	3.17	24.41
4	1.6	3.33	25.70
5	1.7	3.43	25.87
6	1.8	3.53	26.04
7	1.9	3.63	26.20
	3/8 In. × 35 Mesh		
8	1.3	2.64	26.15
9	1.4	3.04	50.91
10	1.5	3.14	53.21
11	1.6	3.23	55.48
12	1.7	3.30	55.76
13	1.8	3.36	56.05
14	1.9	3.43	56.33
	−35 Mesh		
15		5.24	16.38
	Composite		
7, 14, 15		3.78	98.9

SAMPLE NO.1—OLD BEN 26—SHAWNEE RAW COAL—5.40 LB $SO_2/10^6$ BTU

FIGURE 9.2

Segment	Float Density	Lb $SO_2/10^6$ Btu	% of Btu's
1-1/2 In. × 3/8 In.			
1	1.3	0.94	0.11
2	1.4	1.64	22.69
3	1.5	1.67	26.69
4	1.6	1.70	30.52
5	1.7	1.72	30.74
6	1.8	1.75	30.95
7	1.9	1.77	31.16
3/8 In. × 35 Mesh			
8	1.3	1.00	3.49
9	1.4	0.96	38.82
10	1.5	1.08	46.10
11	1.6	1.21	53.00
12	1.7	1.25	53.78
13	1.8	1.28	54.54
14	1.9	1.32	55.28
−35 Mesh			
15		1.75	13.07
Composite			
11		1.21	53.0

ARCH-FABIUS, UNDERWOOD—WIDOWS CREEK RAW COAL—1.71 LB $SO_2/10^6$ BTU

FIGURE 9.3

Segment	Float Density	Lb $SO_2/10^6$ Btu	% of Btu's
1-1/2 In. × 3/8 In.			
3	1.5	5.08	52.78
4	1.6	5.58	58.06
5	1.7	5.76	59.09
6	1.8	5.95	60.09
7	1.9	6.14	61.06
3/8 In. × 35 Mesh			
11	1.6	5.42	28.26
12	1.7	5.64	28.91
13	1.8	5.86	29.54
14	1.9	6.10	30.14
−35 Mesh			
15		13.22	6.81
Composite			
3, 11		5.20	81.0
6, 13		5.92	89.6

PEABODY SINCLAIR 12—PARADISE RAW COAL—9.41 LB $SO_2/10^6$ BTU

FIGURE 9.4

Segment	Float Density	Lb $SO_2/10^6$ Btu	% of Btu's
	1-1/2 In. × 3/8 In.		
6	1.8	4.85	53.53
7	1.9	4.94	53.67
	3/8 × 35 Mesh		
13	1.8	4.82	37.49
14	1.9	4.92	37.68
	−35 Mesh		
15		8.96	7.75
	Composite		
6, 14, 15		5.20	99.0
6, 13		4.84	91.0

PEABODY—SINCLAIR 9 STRIP—PARADISE RAW COAL—
6.86 LB $SO_2/10^6$ BTU

FIGURE 9.5

Segment	Float Density	Lb $SO_2/10^6$ Btu	% of Btu's
	1-1/2 In. × 3/8 In.		
6	1.8	4.92	61.93
7	1.9	4.96	62.10
	3/8 In. 35 Mesh		
13	1.8	5.18	30.60
14	1.9	5.34	31.29
	−35 Mesh		
15		8.38	5.92
	Composite		
7, 14		5.09	93.4
6. 13		5.01	92.5

SAMPLE NO. 8—PEABODY—SINCLAIR 11—PARADISE RAW COAL—
6.23 LB $SO_2/10^6$ BTU

FIGURE 9.6

Segment	Float Density	Lb $SO_2/10^6$ Btu	% of Btu's
1-1/2 In. × 3/8 In.			
4	1.6	5.15	54.77
5	1.7	5.22	54.94
6	1.8	5.30	55.10
7	1.9	5.38	55.26
3/8 In. × 35 Mesh			
13	1.8	5.10	33.96
14	1.9	5.22	34.24
−35 Mesh			
15		7.20	9.93
Composite			
4, 14		5.18	89.0
6, 13		5.22	89.1

SAMPLE NO. 9—AMAX—AYRGEM 11—PARADISE RAW COAL—8.18 LB $SO_2/10^6$ BTU

FIGURE 9.7

Segment	Float Density	Lb $SO_2/10^6$ Btu	% of Btu's
1-1/2 In. × 3/8 In.			
6	1.8	4.66	48.56
7	1.9	4.74	48.69
3/8 In. × 35 Mesh			
13	1.8	4.75	42.53
14	1.9	4.86	42.75
−35 Mesh			
15		10.15	7.79
Composite			
6, 14, 15		5.18	99.1
6, 13		4.70	91.1

SAMPLE NO. 10—PEABODY—SINCLAIR 9 UNDERGROUND—PARADISE RAW COAL—6.50 LB $SO_2/10^6$ BTU

FIGURE 9.8

Segment	Float Density	Lb $SO_2/10^6$ Btu	% of Btu's
	1-1/2 In. × 3/8 In.		
6	1.8	5.33	58.78
7	1.9	5.40	59.22
	3/8 In. × 35 Mesh		
11	1.6	4.90	31.10
12	1.7	4.99	31.43
13	1.8	5.08	31.76
14	1.9	5.17	32.08
	−35 Mesh		
15		11.563	7.58
	Composite		
6, 11		5.18	89.9
6, 13		5.24	90.5

SAMPLE NO. 14—AMAX—AYRGEM 12—
PARADISE RAW COAL—8.19 LB $SO_2/10^6$ BTU

FIGURE 9.9

THE HOMER CITY EXPERIENCE

James F. McConnell
General Public Utilities

The speakers that have gone before me have provided you with an excellent background in the prospects for further development and use of coal, coal utilization technology, and, in particular, the opportunities and constraints to coal cleaning for emissions control.

The "Homer City Experience", as my talk is entitled, is intended to describe the decision making steps and logic leading to the application of deep physical coal cleaning at the Homer City Generating Station to meet SO_2 standards.

Figure 10.1 shows the site.

- Units 1 and 2 are 1969 commercial vintage 600 MW mine mouth coal units, which in Pennsylvania must meet a 4.0 lb $SO_2/10^6$ Btu standard.
- Unit 3 is a new 650 MW unit starting up this year, which must meet Federal new source performance standards.

The local mines here cannot produce coal to consistently meet the equivalent of 4.0 lb $SO_2/10^6$ Btu. Therefore, the Homer City owners were compelled to remove sulfur. A project was initiated in 1973 to design and build a coal washing plant. Because of the value of Btu's, this design provided for heavy medium washing at high gravity (1.8) in conjunction with bypassed coal to minimize refuse losses.

Figure 10.2 depicts this arrangement.

Unit 3, licensed in 1972, was planned with flue-gas desulfurization—there being no apparent alternative.

This set the stage during the utilities economic crunch of 1974 to seek a more cost effective SO_2 control strategy for Homer City.

Figure 10.3 depicts a multi-stream coal cleaning strategy, which was proposed to management for further study. The owners worked with Heyl & Patterson, engineering and construction contractor for the coal cleaning plant at Homer City, to develop a flow sheet which would produce new source compliance coal from available local coal reserves.

Bureau of Mines reports RI 7633 and 8118 give some insight into cleaning preparation potential of coals. The coals of central Pennsylvania are amenable to sulfur removal.

Figure 10.4 shows the relative washability of Homer City reserves to the general seam characteristics in Pennsylvania.

It is apparent from the body of washability data related to Homer City coal reserves that a unique and precedent setting washing plant operating at low specific gravity using dense medium cyclones on fine sizes down to 150 microns could in theory produce a compliance coal with the following fuel specifications.

- 1500 Btu/lb
- 0.9 percent sulfur
- 2.5-3.5 percent ash.

A great deal of engineering effort went into developing a suitable flow sheet. I won't bore you with the details of that flow sheet.

Figure 10.5 shows the estimated economics of a multi-stream coal cleaning system at Homer City. The capital costs are unprecedented for a coal washing plant.

- $50 million total plant
- $32 million incremental cost for Unit 3.

Nevertheless, the estimated capital and operating costs are significantly less than for the then on order lime scrubber. These economics were sufficiently persuasive to allow management to adopt MCCS—not a risk free decision considering:

- No commercial operating precedence at 1.3 sg and 150 micron size
- Uncertain boiler and precipitator performance
- Uncertain predicability of coal reserves.

Because of the engineering difficulty of merging an old design with a new concept, an engineering model was built to help.

Figures 10.6 and 10.7 give some feel for the complexity of a coal washing plant attempting the degree of washing at Homer City.

Figure 10.8 is an artist's rendering of the Homer City coal washing plant showing:

- Main washing plant
- Thermal dryers
- Water clarifiers
- Deep-cleaned coal silos
- Middling coal conveyors.

The cleaning plant at Homer City attempts to maximize the release of mineral matter through crushing or comminution. Comminution occurs either as a result of mining operations or to a greater degree through subsequent crushing.

Homer City coals typical for these seams are high in pyritic sulfur and low in organic sulfur. Therefore substantial reduction of sulfur is possible as shown in Figure 10.9. There are both benefits and penalties from crushing:

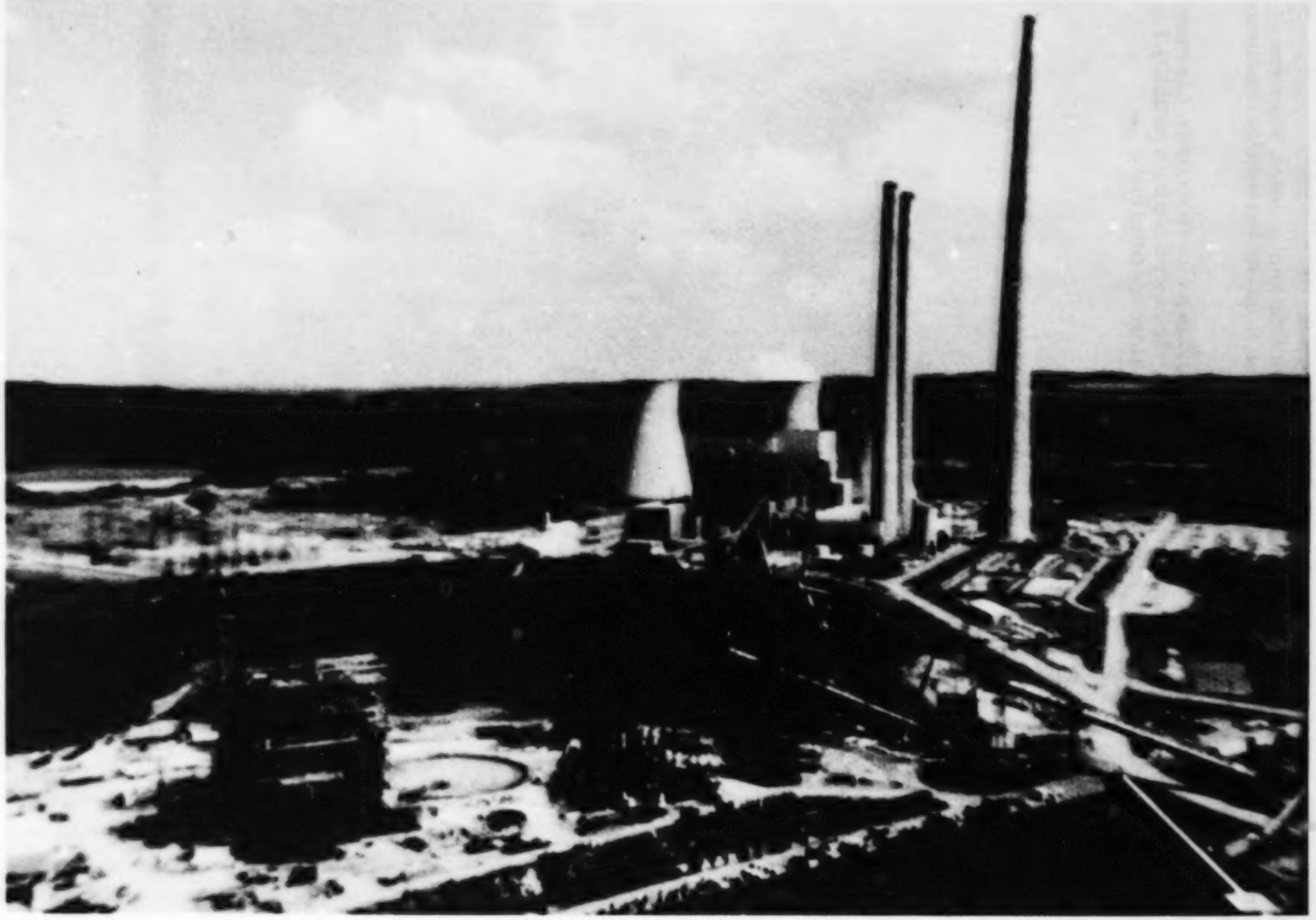
- Fineness releases pyrite and mineral matter.
- Fineness increases difficulty and cost of washing procedures.

What will be done at Homer City will be to selectively wash and blend particle sizes and density fractions of coal to achieve the required coal quality and yield.

Figure 10.10 shows one of the deep mines serving Homer City. The contours indicate sulfur percentage. These show a sulfur variability of 1 to more than 4 percent. What is attempted here is to show one of the major difficulties in developing a coherent SO_2 emission control strategy, that of adequately predicting coal quality in light of coal variability. In-seam sulfur variability is typical. Multiplicity of active mining areas and supplies will dampen the variability of coal but we cannot statistically eliminate it.

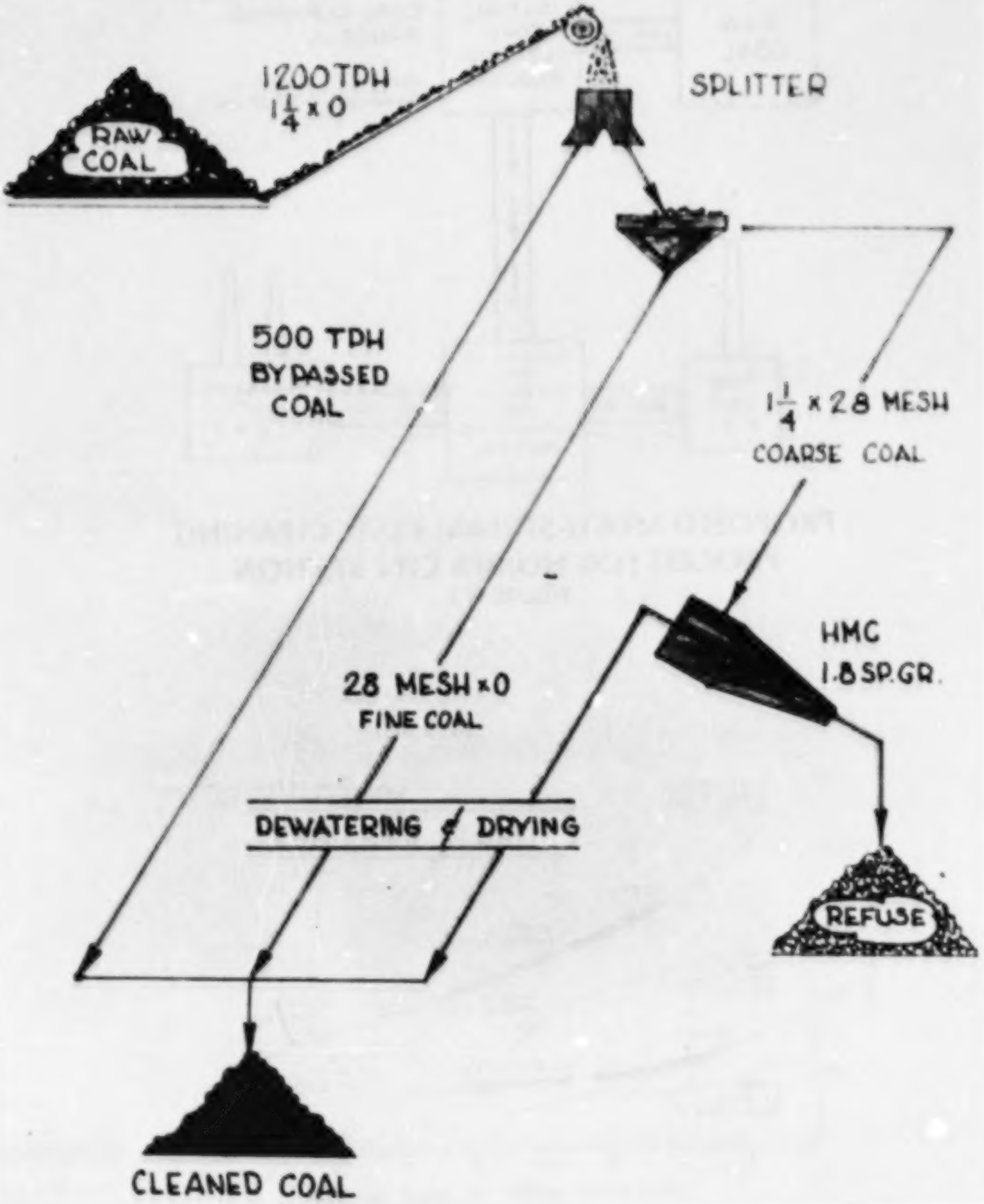
This variability forces control systems to overdesign to meet short term extremes. Short term excursions in emissions from tall stacks have no measurable effect on air quality. Nevertheless regulations are based on 3-hour averages.

This is totally impractical when considering the wide variability of coal quality. Optimistic assessments of the amounts of compliance coal fail to adequately consider the impact of variability. The Homer City owners are particularly sensitive to this issue in long-range operating plans.

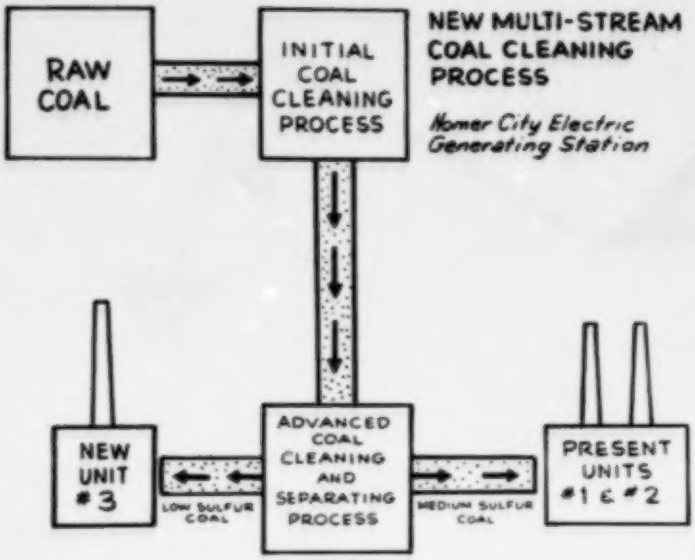


HOMER CITY GENERATING STATION SITE

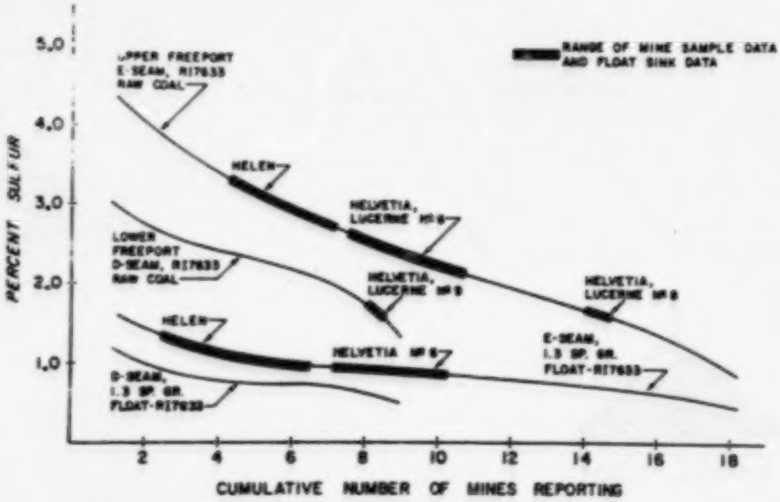
FIGURE 10.1


1200 TPH
$1\frac{1}{4} \times 0$
RAW COAL
SPLITTER
500 TPH
BY PASSED
COAL
$1\frac{1}{4} \times 28$ MESH
COARSE COAL
HMC
1.8 SP. GR.
28 MESH × 0
FINE COAL
DEWATERING & DRYING
REFUSE
CLEANED COAL

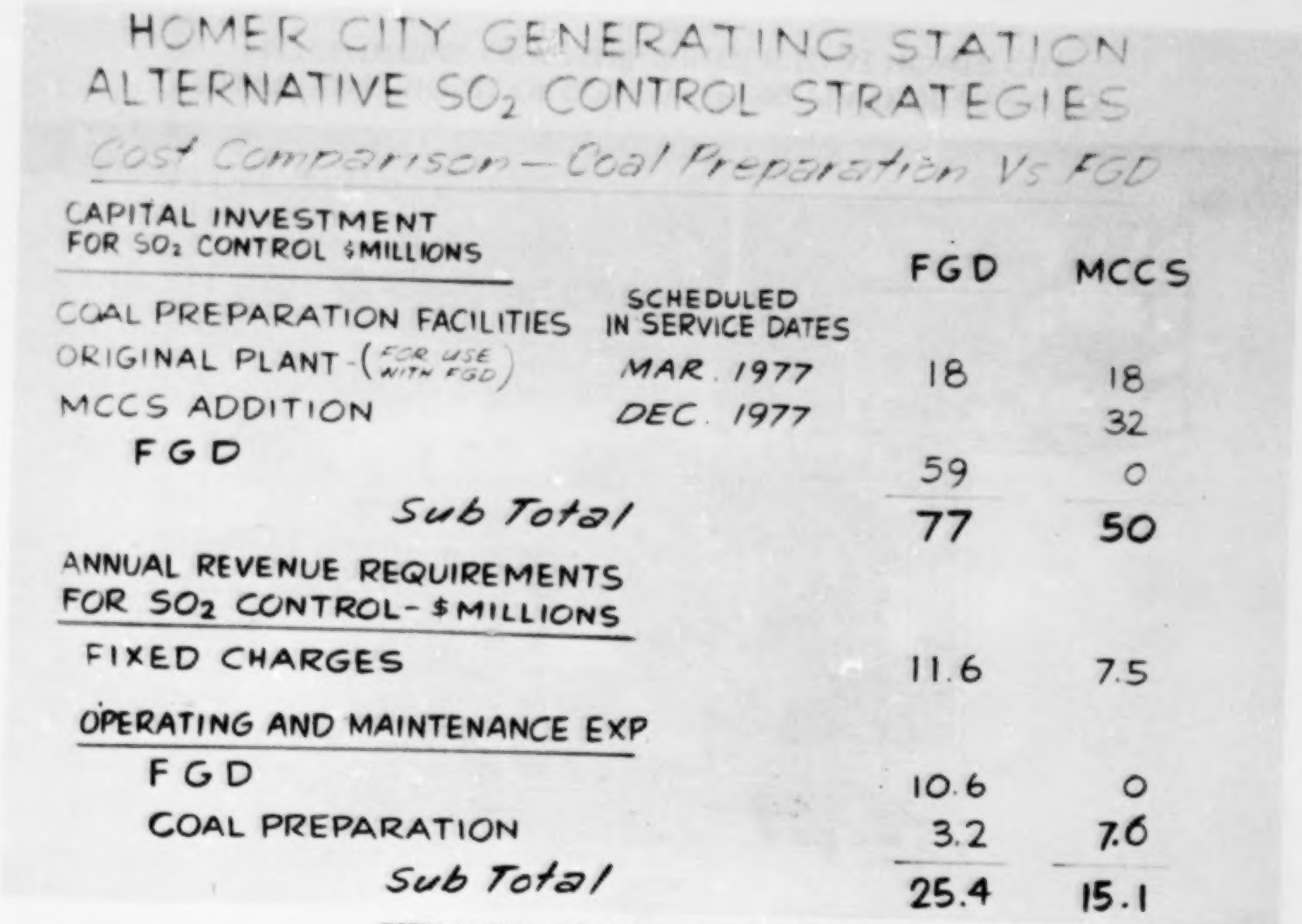
SCHEMATIC REPRESENTATION OF
HOMER CITY COAL CLEANING PLANT
FIGURE 10.2


NEW MULTI-STREAM
COAL CLEANING
PROCESS
Homer City Electric
Generating Station
RAW COAL
INITIAL COAL CLEANING PROCESS
ADVANCED COAL CLEANING AND SEPARATING PROCESS
NEW UNIT # 3
LOW SULFUR COAL
MEDIUM SULFUR COAL
PRESENT UNITS #1 & #2

PROPOSED MULTI-STREAM COAL CLEANING PROCESS FOR HOMER CITY STATION
FIGURE 10.3



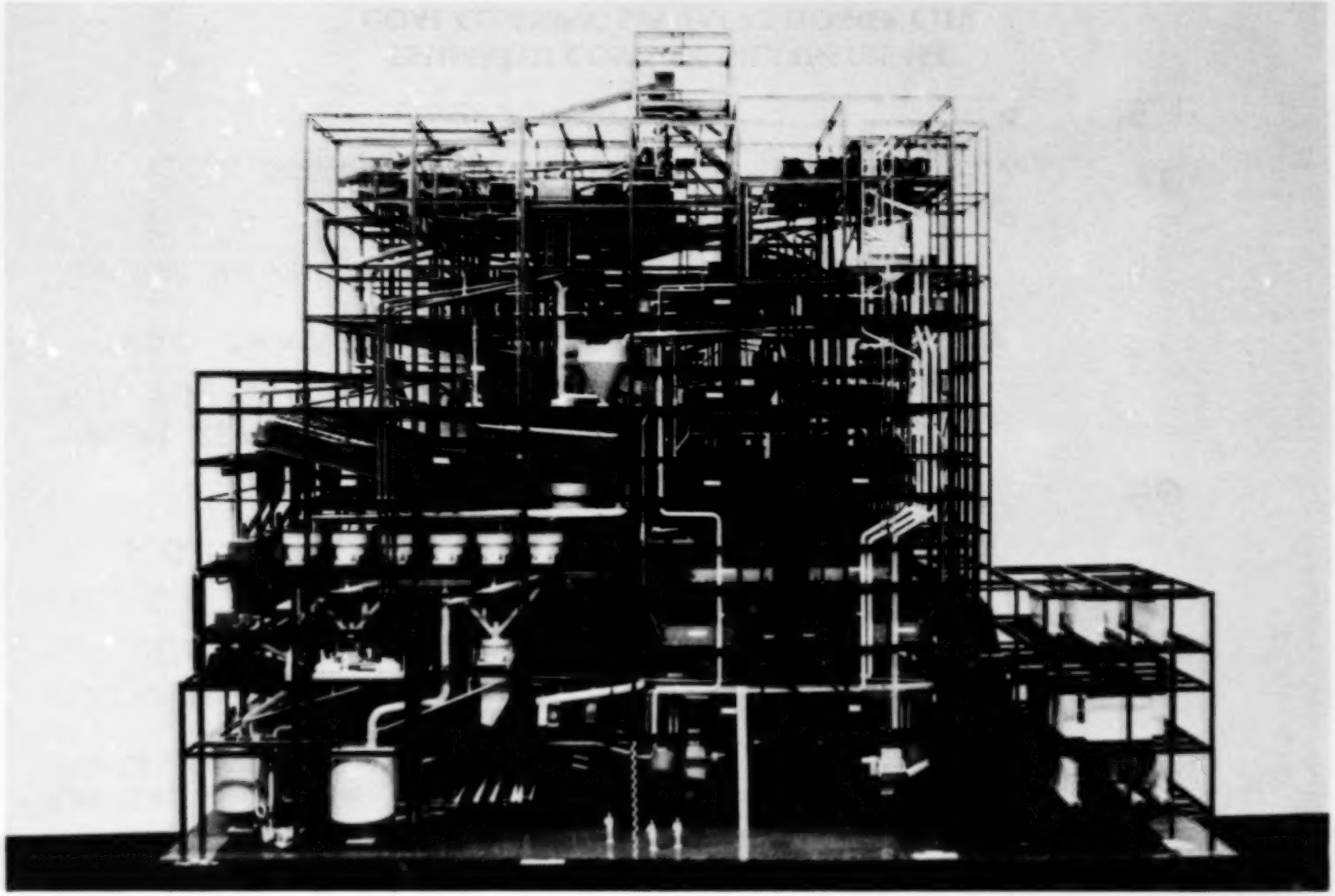
RELATIVE WASHABILITY OF HOMER CITY RESERVES
FIGURE 10.4



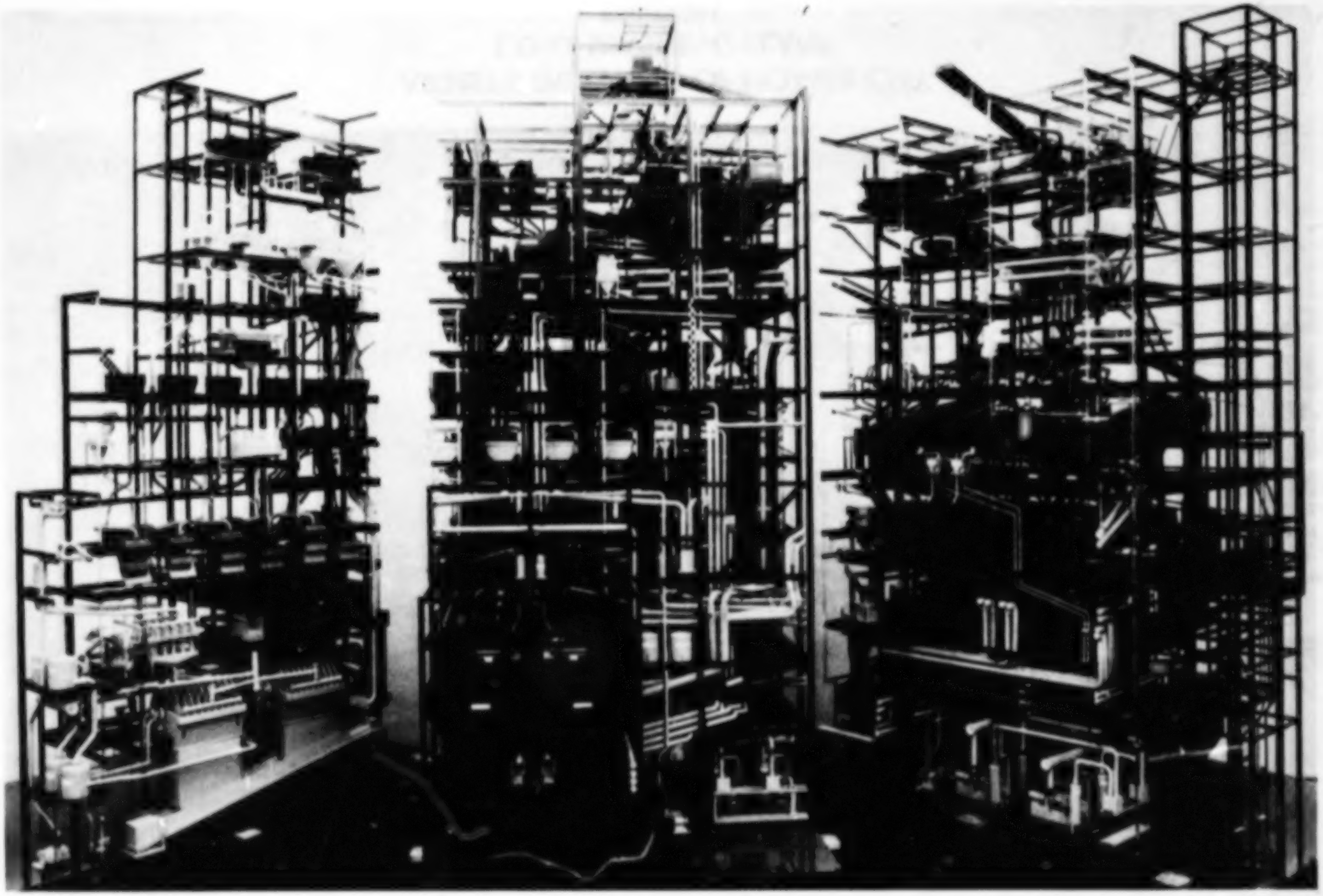
HOMER CITY GENERATING STATION
ALTERNATIVE SO_2 CONTROL STRATEGIES
Cost Comparison — Coal Preparation Vs FGD

CAPITAL INVESTMENT FOR SO_2 CONTROL $MILLIONS	SCHEDULED IN SERVICE DATES	FGD	MCCS
COAL PREPARATION FACILITIES			
ORIGINAL PLANT - (FOR USE WITH FGD)	MAR. 1977	18	18
MCCS ADDITION	DEC. 1977		32
FGD		59	0
Sub Total		77	50
ANNUAL REVENUE REQUIREMENTS FOR SO_2 CONTROL - $MILLIONS			
FIXED CHARGES		11.6	7.5
OPERATING AND MAINTENANCE EXP			
FGD		10.6	0
COAL PREPARATION		3.2	7.6
Sub Total		25.4	15.1

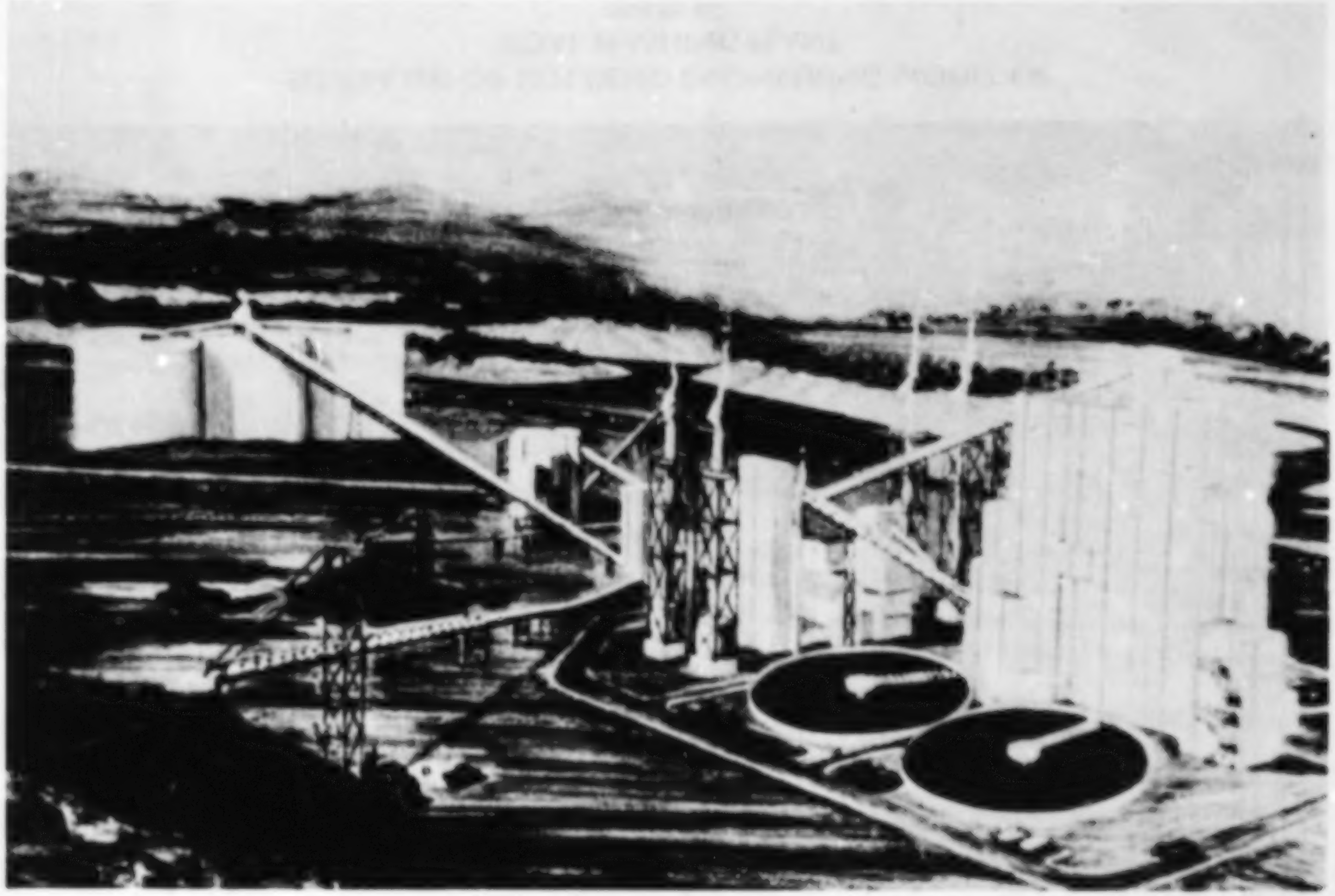
ESTIMATED COSTS OF MULTI-STREAM COAL CLEANING SYSTEM AT HOMER CITY
FIGURE 10.5



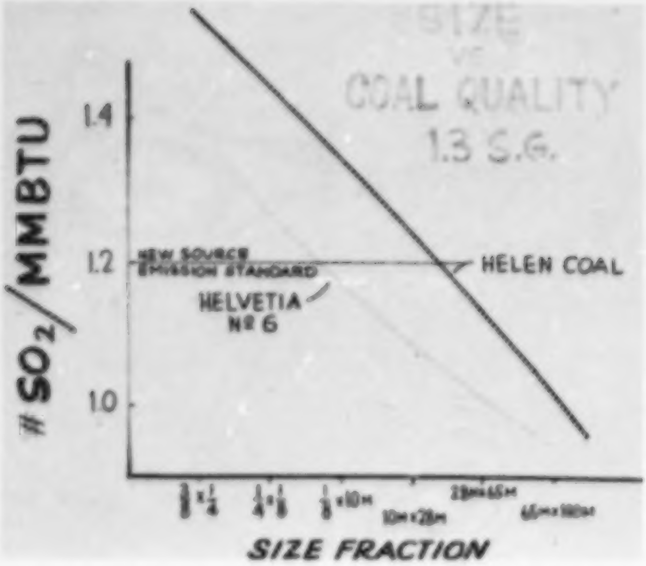
ENGINEERING MODEL OF COAL WASHING PLANT DESIGNED TO MATCH DEGREE OF WASHING REQUIRED AT HOMER CITY
FIGURE 10.6



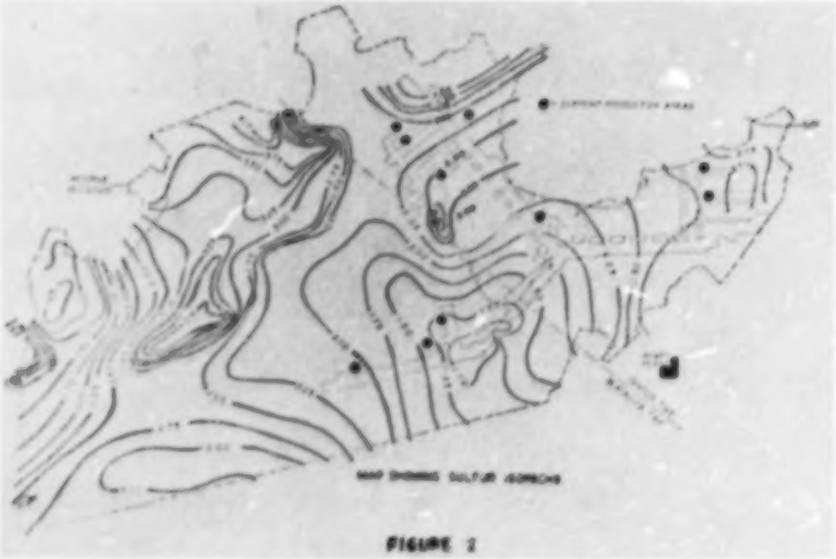
SEPARATED OR EXPLODED ENGINEERING MODEL OF COAL WASHING PLANT
FIGURE 10.7



ARTIST'S DRAWING OF HOMER CITY
COAL WASHING PLANT
FIGURE 10.8



RELATION OF COAL SIZE TO SULFUR EMISSIONS FOR TYPICAL HOMER CITY COALS
FIGURE 10.9


MAP SHOWING SULFUR ISOPACHS
FIGURE 2

MAP OF A DEEP HOMER CITY MINE SHOWING SULFUR VARIABILITY
FIGURE 10.10

PANEL DISCUSSION AND CONCLUDING REMARKS

Edward W. Ungar, Moderator

UNGAR: I would like to start out by introducing the panel. I think that we are very privileged to have this group here: Mr. Bill Poundstone, Executive Vice President of Consolidation Coal; Mr. Bob Reeves, head of the Environmental Engineering Division, American Electric Power; Dr. Bill Gouse, Deputy Assistant Administrator for Fossil Energy of the Energy Research and Development Administration; Mr. Kurt Pralle, Vice President of City Bank; and Mr. Frank Princiotta, Director of the Energy Processes Division, U.S. EPA. I have asked each of the panelists to open with a 5-minute discussion. Following that, we will have some discussion among the panelists and then open discussion from the audience. . . . I think that I will just start from my left and work down. Bill.

POUNDSTONE: We are coming to the end of a rather long session, so much of what I had planned to say has already been said. I will merely make a couple of points. I think the key point is, and it has been mentioned earlier, that we have tremendous variability in the coals. It seems that this point has been overlooked for lack of knowledge. We have seen examples of coals like Homer City and some slides in the earlier paper on principally central Pennsylvania coals that are particularly amenable to significant sulfur reductions through cleaning. I don't quarrel with this for a minute, but I would submit that I do not believe these are typical of the coal reserves throughout the country that lie ahead of us. In fact, they are not even typical of all the coal in the Central and Western Pennsylvania area.

One other point is that I have some argument with the belief by some that washing coupled with scrubbing may be more economical than scrubbing per se. My own analysis of this is that coal cleaning to get at the easily removable part of the pyrite is probably justified economically. But in many, many instances where scrubbing is required, I believe that the incremental cost of cleaning, beyond getting at the easily had sulfur balls, exceeds the incremental costs of scrubbing.

I would make one other point. And that is that it has only been in recent times that the sulfur content of coal has become a tremendously significant dimension in the coal supply problem. Delivery costs per million Btu have been for many years our prime concern. While sulfur has always been important, it has not been our prime goal. Now the result of this I think, is that many coal operators, myself included, until recently didn't know nearly enough about the sulfur contents of our coals. In fact in some areas, take Illinois for instance, where the total sulfur content is relatively uniform, it was common practice not to sample for sulfur on all of the holes that were drilled, in the interest of cost savings. In many other areas, sulfur forms, to determine the amount of organic, were not run except on an occasional hole and only total sulfur was recorded. So, many of us were under the impression that organic sulfur tended to be relatively uniform within a given seam, and that the difference, the variation in total sulfur content, came about by variations in the pyritic content or whether you hit a sulfur ball or not.

Well, recently we have been looking much more closely at this issue and I have to admit, even though I have been in the industry for 30 years, I am learning some things about sulfur content that I was not fully aware of. What I find is that in vast areas of the coal reserves that lie ahead of us, such as the Pittsburgh seam in Northern West Virginia, which certainly constitutes one of the biggest low-cost mining reserves available, we do have a much greater variation in organic sulfur than I believed. I looked at a substantial field containing several hundreds of millions of tons and it so happens that in this particular field we did have organic as well as total sulfur content. I would like to give some figures to illustrate the point. Within this particular field, the minimum total sulfur reading was 1.86 percent, the maximum was 5.46 percent with a mean of 3.23. When we look at the organic content of those same holes, we find the minimum to be 0.81, the maximum to be 3.42 and in effect we have a higher percentage variation in the organic sulfur than we do in the total sulfur.

In looking quickly, I think that this same phenomenon exists in Illinois and in other major coal basins, not necessarily in Central Pennsylvania or Southern Appalachia. Now, regarding the Bureau of Mines Study—which I think was an excellent one and I certainly have no quarrel with the analytical procedures—where they sampled some 450 coals in Appalachia. I would point out that these samples

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are a single-point-in-time sample that were taken in one day. Thus, all of the conclusions that have been drawn from that sample data do not necessarily mean that in the next month or the next year those sulfur contents will hold. In essence that is pretty much what I have to say.

REEVES: I would also comment that an awful lot of the points that I had to make here were covered in the past day and a half. However, I think that one of the first comments that I would like to make is with respect to your cover page on the program—the title, which was phrased as a question, which I tend to think appropriate for this meeting. Second, we at AEP feel that coal has to be used in order to meet the energy demands. AEP certainly is one of the larger users, maybe the second largest user, of coal and our interest in coal cleaning is quite obvious. We have a system of approximately 17,500 megawatts of which essentially all is coal-fired. We have one nuclear operation. In 1976, we burned approximately 35 million tons of coal. So our interest in coal and coal cleaning—in all aspects of coal cleaning—is vital.

However, I think that I have to comment with regard to what I understand is the energy policy and on one aspect of it that I am not quite clear on. I seem to get the tone that there will be something about that policy that will in effect mandate scrubbers on all units, regardless of the sulfur contents in fuels. I am not too sure that is correct, but I have a feeling that it has been mentioned off and on. If this is the case, in my opinion the coal cleaning concept could be of no significance. In fact, all the money now being spent or proposed on R&D projects in this area may not be necessary at all. In essence, the policy in some cases appears to me one that could cause a reversal or backing away from coal toward nuclear energy, which I understand is not one of the most desired results of this energy policy.

You can't use coal and at the same time mandate its use, and then at the same time tend to strangle it with a policy calling for essentially no alternatives, or in some cases, even more stringent controls. I believe an extensive compilation and a study of all pertinent facts are essential before any policy or standard is revised compelling the construction or continuation of FGD systems as the primary, if not exclusive, means of reducing sulfur emissions from a coal-fired utility. In my opinion, recognition should be given to the promising alternatives to scrubbing, which are presently under development. In the absence of inhibiting factors, proper incentives would quicken the pace of the new technology, such as coal cleaning, or coal conversion, or what have you. The fact that the problems with scrubbers are evident in and of itself requires consideration be given to alternative technology. Any downward revision of the standards, or mandating of one technology, in my opinion, could abruptly nullify existing research and alternative technology.

Quite frankly, in other words, I would suggest we look at the monies being spent by ERDA, or EPA, or other private industry in this area; whether they are necessary or not if the end result of such a policy would be mandating scrubbers. In addition, mandating scrubbers or a downward revision or change in the NSPS, again would retard, in my opinion, or even preclude, any future development. There is little incentive to undertake risks on coal development or make financial commitments when there is no market.

I think that it is necessary for me to also make a comment or two about a couple of statements that were made yesterday regarding the imaginative uses of coal. I would hope all of us that are in the coal business, or essentially in the coal business, would apply this philosophy to the development of such technology and/or standards. Another factor that I understand is part of this policy is the rigid enforcement of existing, let alone of any new, standards. To me, if this is literally enforced, then some of us may be in more serious trouble than we think, since, in my opinion, compliance is not a one-time event but a constant requirement. From what I know of scrubbers as to meeting rigid constant monitoring control as is the case with coal supply or low-sulfur coal variability, we are going to be down an awful lot of the time, in my mind causing a very significant impact on the energy problem.

Mr. Mullan and Mr. Poundstone mentioned this in their comments yesterday. If there is no room for variability in these regulations, and they are ridigly enforced, we are in trouble. Now some may say that, "oh well, you can operate on 1 or 10 day variances." Well, if that is the case, why then the need for such a rigid hour-by-hour control of requirements.

Regarding the other comment made yesterday to the Ohio situation, I believe by Mr. Mullan (in fact there was a reference made to it at lunch), AEP does operate in Ohio. We have a subsidiary name of Ohio Power Company. And I can tell you that Region 5 EPA regulations are such that Ohio Power can't essentially burn all the local or indigenous coals. In fact, EPA regulations for Ohio, in my opinion, couldn't be a better endorsement of the tall-stack philosophy.

I believe that there are many areas in this country where section approach can and should be used. It very simply recognizes what the real data shows, what a well-designed facility is, and that where ambient air quality is being met, there is no need for stringent emission controls. Of those areas where some control is required, coal cleaning can be and could be effective in achieving these goals. In our particular Ohio facilities—and we operate a very significant real-time air monitoring network in our facilities—every one has for many, many years shown the data to in fact meet the ambient air quality standards that have been established.

Another comment yesterday—I hate to raise it again—was made with reference to Laseen and the Bruce Mansfield Station. Unfortunately none of those people are here to make any rebuttal but I think it is necessary to point out, I am not positive of this but I do believe, that the Laseen Station is not required to meet new source performance standards. Secondly, I think it is of interest that for the second unit being built out there at Laseen, compliance strategy is with low-sulfur coal. I would suggest that any of you that are familiar with the Bruce Mansfield Operation, if you are interested in what those costs are, those people would be very happy to tell you. I can assure you that they approach $150 a kilowatt today.

And the other thing that was lightly touched on seemed to imply that there was a little bit of a sludge problem. Well, I am going to tell you the highest dam east of the Mississippi has been constructed up there to hold back this garbage. Land use concepts you might want to take a look at.

I believe coal cleaning can become a competitive approach to meeting emission standards if given a chance and not excluded by policy. The merits of front-end cleaning to those of us who operate 600, 800, and 1300 megawatt units is obvious and any kind of devices that we have to attach to these large base-loaded type units cause problems. It is the financing and ownership of coal cleaning plants that is a problem. American Electric Power does own and operate a substantial number of coal operations and, in our particular case as it would relate to our own mining operations, we would hope to be able to raise the necessary financing to move forward with some coal cleaning technology. A market for clean coal in my opinion is great. But again, I think that it could easily disappear if we are not careful in terms of the policies developed with its use. Demonstration needs and R&D needs in my opinion are very obvious and essential, but here again, I am very concerned about just what this policy will end up doing in terms of its impact on such very important matters. Doubling our coal production from 640 million tons in a year to some 1.2 billion per year in only 8 years is going to be a very difficult thing to achieve. The investment and capital requirements for such growth, in terms of the uncertainties that we are involved in, have to be given very serious consideration. We at AEP are vitally interested, and we have been for many, many years, in what we commonly refer to as front-end cleanup systems. I think that we have made that statement time and time again so we are vitally interested in the development of these front-end processes. Thank you.

GOUSE: Good afternoon. I am not prejudiced by the previous proceedings so you have to excuse me for what I might say. In ERDA, we have approached this problem from a different point of view because we are not concerned with the current generation of electricity technologies but with future schemes to make gases and liquids from coal, or advanced power systems such as MHD, or combined cycles, or fluid-bed combustion using limestone or dolomite.

In the execution of this R&D program, you have to look at what you think environmental standards might be not today, but 10 to 15 years from now, and try to see what you are doing in the R&D program—to see whether you have a hope of doing anything that could be implemented. As a result, we have taken a hard look at physical cleaning of coal, chemical cleaning of coal, use of scrubbers, etc., just to see what it means to, say, the economics of atmospheric fluid-bed combustion of coal for the generation of electricity. That is, do you run a run-of-the-mine coal in? Do you clean it? Will you have to use scrubbers as well? If you have to put all of these things together, should you bother with the program? That kind of question.

One of the things that we learned very early backs up what Bill Poundstone said. Coal is extremely variable, not only in sulfur but in everything—even the carbon configuration itself, the ash content, the nature of the trace elements and everything. If you are trying to run a continuous process with any kind of throughput that has any very delicate anything in it, you find out that you have big trouble.

We have learned that in many cases cleaning up the coal in a liquefaction process destroys its reactivity. The ash content is a more effective catalyst than any the catalyst people have been dreaming up to use. Or, small trace elements will come through and poison the reaction. One of the easiest ways to see that coal is so variable is that the hydrogen requirements in the process, either in gasification or liquefaction, vary all over the place, primarily because of the sulfur variation. We would also agree that the organic and the inorganic constituents vary all over the place, as well.

As far as physical cleaning is concerned, we have concluded that you know how to do a great deal; a lot of it has been developed elsewhere for high-ash coals but is available here. Whether or not it is used extensively really depends on what the regulations are going to be—what does best available technology really mean, and what will the standards be in 3 or 5 years from now, as opposed to today.

That does not mean that we have answered all the questions on physical cleaning or that you couldn't answer them better. But those technical unknowns in the physical cleaning aren't what are limiting people moving to it. We have done some studies that indicate that you may want to combine coal cleaning with scrubbers. But again, it depends on what the standard is going to be and how you interpret the variability. We have also looked at this with atmospheric fluid beds because we would like to cut down the amount of limestone that we would have to introduce. But even with coal cleaning and with limestone recirculating in the bed, you have to put scrubbers on as well because you still have sulfur coming through. And I don't think that you would do any of the others if you had to do that.

A solvent-refined coal today looks like it is acceptable, but one kind of policy interpretation would require the use of scrubbers with solvent-refined coal. Well then, you wouldn't use solvent-refined coal because there would be no advantage.

If you go far enough with the standards, the only route that we have available to us that could meet almost any standards that you want is to make a chemically pure kind of synthetic fuel from coal, which you can do. We can make a fuel from coal, either gaseous or liquid, that has no nitrogen, sulfur, no ash. And, with the appropriate combustion design, there won't be any sulfur, any knocks, or any particulates. But you are talking about a fuel price of about 3, or 4, maybe 5 times what you are thinking about paying right now. And that decision to impose that fuel charge or an equivalent fuel charge for the generation of electricity ought to be made pretty carefully, but it can be done.

We are just now starting fairly extensive experimental work to try to understand the trade-offs between coal cleaning and chemical conversion. We know it is an important factor. Back-of-the-envelope calculations tell us that there certainly are cases that, if you are making liquids, you are going to want to clean before running into the process or gases. There are also back-of-the-envelope calculations that tell you that probably for some coals you wouldn't do it. We really don't have a good enough data base to say definitely one way or the other what you do in a particular case. But through a series of contracts and in-house work, we're setting out to develop that information.

PRALLE: A quick clarification—I am not a banker. I am a mining and metallurgical engineer who, after 20 years in the industry, decided that he better find out where all of the money is coming from. So I went to work for the world's biggest bank, First National City Bank.

City Bank has a very vast exposure to the mining and utility industry. We are, therefore, watching coal and all associated matters very, very closely. Coal mining and utilization will increase despite government policies. In fact, if you can believe the table on page 95 of Mr. Carter's Energy Proposal, coal usage will get to its target with or without this proposal. We do not think at City Bank that it is possible to double coal production to 1 billion 200 million tons by 1985. We think the industry will do quite well if it reaches somewhere between a billion and a billion 50 million tons per year.

We are financing and seeing many mining projects in the coal industry. Lately the average has been about $40 to 45 million per million tons per year annual capacity for a new project. Almost every one of the larger mining projects include cleaning plants and the average cleaning plant cost is somewhere between $10 and 12 million per million tons of clean coal per year. Therefore we are looking at an expenditure for the next 10 years of about $2 billion per year in coal mining and cleaning.

Now you say, where is this money coming from? There is plenty of money around. Banks are very willing to lend. What there is a critical shortage of is good credit. I would like to very quickly talk about that a little bit. Traditionally, the mining industry in this country has financed projects with equity funds, meaning current cash flow and retained earnings. One of the several reasons for this has been that mining companies never had any kind of a bond rating. Even today, there is only one mining company in the United States with a AA rating, and that is ENCOL. So, the money that has been available in relation to the funds required for new projects has decreased, because projects have increased in magnitude and capital requirement.

Since the early 1960's, this trend has accelerated and mining companies have to go to their commercial banks and borrow funds. Today, if you look at the ratio of debt to equity, you are probably approaching something like 70 to 30. Now this includes all of the new financing techniques including project financing, where in theory at least, the project itself borrows and not the sponsoring companies. Now, in coal mining you not only have big responsible strong companies, but also much of the further increase in the mining and production will have to come from small companies. Small companies have neither equity nor borrowing capacity. This compounds the problem.

So what alternatives then can we look at? We know that there is not enough equity available. Well, one way of solving that would be to increase the available equity by having coal companies acquire new parents. We have seen that in years past, where many of the big coal companies were acquired by oil companies. This is continuing. We see coal acquisitions at the rate of one every 10 to 15 days. I have a whole thick file of just clippings of the published information on these. Also, in the same form of bringing new equity money into the industry, we might have entirely new companies, who have no relationship to coal mining, enter into the picture and bring funds, either by acquiring a small company and building it up or starting all over.

A second way would be to have companies come in and act as an intermediary, buying, let's say, output from miners, cleaning, and reselling it. We are seeing this already in the metallurgical field. This again would bring money into the field and it would bring borrowing capacity into the field that doesn't exist now.

A third way would be to involve the utilities, or rather consumers, more deeply than they are already. Utilities already own a good many coal mines. They already own probably the majority of all new unit trains in this country. And, this trend will continue. Utilities could conceivably own cleaning plants independently of the miners, either at the point of the mine or at the consuming plant.

One more point, you might say that you are talking about the availability of bank money, but surely there are other forms of money around. There is the bond market. And, of course, if you involve the utilities, utilities traditionally have made extensive use of the bond market because utilities traditionally are highly rated companies. So bringing utilities into this field of financing should access more money.

You might also say, "What about the Federal government?" I would say, "Forget it." You might talk as the good senator at lunch, in terms of perhaps hundreds of millions of dollars, but certainly not in terms of billions of dollars and that is the magnitude that we are talking about. So in the future, you will continue to look to the commercial banks to provide the bulk of the finance required to bring our present 650 million tons per year to about the 1,050 million mark.

PRINCIOTTA: I think some clarification on the status of SO_2 control standards might be helpful. I think Steve Gage, in his introductory remarks, mentioned some of these points but perhaps we can expand on that a little bit. Just so that we are all up-to-date on just what is happening regarding the possibility of tightening of standards, I will give you the best of my knowledge. And I am to some extent involved in this personally. First of all—and I am sure that you are all aware the present clean air amendments have, of course, new-source-performance standards for steam generators greater than 25 megawatts electric approximately—the present standard, as you know, is 1.2 lb $SO_2/10^6$ Btu of fuel burned.

Something that we haven't talked too much about during the course of this meeting is the existing state implementation plans that call for varying degrees of sulfur control on existing sources. The center mentioned that there are moves afoot to perhaps make some of those state standards for existing sources less stringent or more lenient. In other words, just what is needed to meet the ambient air quality goals, which is really what that part of the clean air act is all about. This of course is very relevant to coal cleaning because, as I will mention later, that is one of the areas in which coal cleaning can fill a role.

Regarding tightening of the standards, and this may lead to some confusion, there are two parallel, really separate, but related efforts that are going on right now that could conceivably lead to some tightening of the SO_2 standards for these steam generators. The more imminent of the two is the possibility that the Congress will amend the present clean air act, within probably the next 2 to 3 weeks, to include a BACT (Best Availability Control Technology) Provision. Now what does that mean? My understanding is that when the Congress deliberated on the clean air amendments of 1970, they basically were hopeful that the standards that were set for all the various industrial sources would be technology based. That is, the Congress apparently felt that it was not necessarily appropriate for an existing fuel to meet a given standard, such as low-sulfur coal in the West, since obviously, if a technology were imposed on such facilities, one can do better as far as minimizing emissions is concerned. It should be pointed out, that the new source performance standard, Section 111 of the present amendments, is not related to health. It is basically trying to keep the ever-accelerating emissions of the various pollutants under control. Emissions not related to ambient air quality. I think that is important as well.

Now what does that mean? Suppose the Congress does pass this BACT Provision, which may be likely since the administration is behind such a move. I have talked with the people at EPA who would have to actually write the regulations and implement any such BACT approach, and I can say that they have not yet come to any conclusions as to just what the form of the regulations to implement BACT would look like. But just let me give you a few examples of some of the possibilities.

One could conceivably set a standard that would call for, let us say, 70 or 80 percent sulfur oxide control on all new units (and by the way these are only new units that we are talking about now). This, of course, would basically eliminate using low-sulfur coal in the West, but conceivably one could still use low-sulfur coal east of the Mississippi. Another possibility would be a much tighter standard, like a 90 percent control, which is, in some people's opinion, consistent with what scrubber technology can do. This, of course, would essentially eliminate completely the low-sulfur coal option alone. I think that there are very few coals, if any, that could meet such a standard.

Another possibility would be a tightened standard in terms of pounds per million Btu. Instead of 1.2, it could be tightened to 0.6, or 0.8, or whatever is deemed appropriate. This would have the same effect probably in eliminating the low-sulfur coal option. So that is up in the air, but my understanding is that it is not very probable that the implementation approach will say you shall use scrubbers. I think that it is likely that it will be some kind of emissions standard that will not preclude the use of other technologies that may be available, such as fluidized-bed combustion. Of course this is not in the implementation phase yet, but I am just giving you some of my insight based on what I have heard so far. So I don't think that it is likely that we will be ruling out these other technologies.

Now the other parallel activity that is going on is, even assuming that the Clean Air Act doesn't get amended, Section 111 of the Clean Air Act reads that standards should be set based on best demonstrated commercial performance of a given control technology, taking into account cost. The implication of this is that, as technology improves, the standards should be tightened. So the EPA, under some pressure by the environmental groups, particularly the Sierra Club, is now in the process of considering, on the present Clean Air Act amendments, the tightening of the present NSPS for steam generators for sulfur oxide. And again, this standard might look a lot like the BACT Standard. Namely, it may end up as a 90 percent control across the board standard. It could end up as a 0.6 or 0.8 lb/10^6 Btu standard; or it may end up that the EPA will conclude that, based on everything they have seen, it is not warranted to have this type of standard. That is what this panel that EPA has set up will deliberate on. I just wanted to clarify that situation a little bit at least.

So what does this mean to coal cleaning? I think that before I get into that, briefly let me at least bottom-line my impressions as to where these various control technologies stand. To some extent I am going to agree very closely with some of the conclusions that Dick Balzhiser came to earlier yesterday. I think that between now and the late 1980's there are only three ways of meeting the sulfur oxide standards for new and existing sources; flue-gas desulfurization, utilization of nationally occurring low-sulfur fuel, and physical coal cleaning in some cases. Now if the standards are tightened through either one of those two mechanisms that I mentioned between now and 1985, we are pretty well limited to flue-gas desulfurization or something that might involve a combination of flue-gas desulfurization either with a low-sulfur coal or with physical coal cleaning. In the post-1985 period, I basically agree very strongly with Dick Balzhiser's conclusion that, of the emerging technologies, really only fluidized-bed combustion at this stage of the game appears competitive with pulverized coal boilers with scrubbers on them, assuming electricity is your end product. Now I am not talking about high Btu gasification. I am not talking about replacing natural gas with lower medium Btu gas for industrial uses. That is a separate subject and I am not addressing myself to that.

Coal gasification and coal liquefaction, particularly for base-loaded units, based on what we know about the economics now, looks like a loser to produce electricity. As Dick pointed out, there is hope here though, that as we improve our gasifier technology, which rests in gasifiers that have larger throughputs with combined cycles that will give us higher overall efficiencies, maybe we can turn that around in 10 years or so. I doubt it personally, but I am by no means an expert in this area. Therefore fluidized-bed combustion, I think, looms as a very important technology. One thing scares me a little bit about fluidized-bed combustion technology. Can it meet these tighter standards that might come along based on these two parallel activities that I mentioned? I talked to Jerry Houndon of TVA today, and he feels very strongly that they cannot meet a 0.6 lb/10^6 Btu standard, for example. I don't know. I have seen data that leads me to believe that it is pretty close. I hope that the standard-setting people will take that into consideration in any tightening of the standard. In my view at least, we should not preclude what looks like an attractive technology coming down the pike, and what little impact that I might personally make on that exercise will be pushing in that direction.

What does this mean? Where does coal cleaning fit in? I will just basically list some of those applications for which I think coal cleaning really has some potential. As Steve pointed out in his introductory remarks, the potential is based on one simple fact and that is that there is no cheaper way of removing a given amount of sulfur from coal. I don't think that will be debated by too many people.

Where can we use coal cleaning? I think clearly for retrofit applications; for applications to meet state implementation plan standards, which are in some cases in the 2, 3, 4, and 5 lb/10^6 Btu range. Coal cleaning, in many cases, can meet these standards in the lowest cost modes. I understand that TVA is strongly considering using coal cleaning to meet these SIP requirements on at least two of their plants. I am sure that other utilities are considering such use.

We have heard, and unfortunately I missed this particular paper by Larry Hoffman, but I think I have read earlier papers by him, and he points out the potential of using coal cleaning with FGD. Again, keeping in mind that you can remove as much sulfur as you can cheaply with coal cleaning, it means less scrubbing is needed downstream. It means lower costs. I think the multistream approach at Homer City, applied to industrial users, makes a lot of sense because there is no good presently available control technology below the 25 megawatts size range. Installing scrubbers on these very small systems may not make much sense because of economics.

Finally, I think that coal cleaning has potential to be used in conjunction with some emerging technologies, such as fluidized-bed combustion, as Dr. Gouse pointed out. Again, that is not an inexpensive technology and it is more expensive, even with fluidized-bed combustion, to remove a given amount of coal than it would be for coal cleaning. So, it probably makes sense to consider for amenable coals, the use of coal cleaning prior to the actual fluidized-bed combustion process. I guess that in a nutshell summarizes my view on where coal cleaning fits in the relatively complex picture that we have today.

UNGAR: Thank you, Frank. Let me first turn to the panelists and ask whether they have any questions for each other? (Pause) Ok, let's open up questions from the audience. Please step to the mikes and identify yourself.

JOE COREY, FEA: Referring to the washability study (directed to Frank Princiotta), some of this coal, if you do wash, tends to look like a metallurgical grade coal. I was wondering if you gentlemen have addressed the fact that if you do wash it, you can sell it as a met coal, how much of this (in the washability study) would qualify as a met coal, and how much would qualify as a steam coal, after you have washed it?

PRINCIOTTA: I am sorry. I am not personally qualified to answer that question. Can anyone in the audience? Jim Kilgroe, do you feel that you can? No.

POUNDSTONE: I can maybe answer that. The Appalachian coals seem to (unintelligible). So whenever you find coals from that particular area that are low in sulfur and low in ash they are by definition metallurgical in grade. Certainly, the qualities that were shown on those Cambria County mines and lower Freeport mines would be very desirable metallurgical coal in today's market because I know those seams have a high code strength.

COREY: I noticed that too. In light of that, how much of those reserves are tied up by private ownership and how much would be available to utilities if you did clean them and nobody wanted to put them in a coke oven?

POUNDSTONE: Again, one of the reasons I don't believe that there is that much coal that will qualify for this type of washing is the fact that we have been looking for metallurgical coals in that area for a number of years and are making metallurgical coals out of coals that have 2 percent and higher sulfur, in that general area. So, I think that you are right. There is going to be a great tendency for those kinds of coals that are amenable to that treatment to go into the metallurgical market.

COREY: I have one more question that refers to the 1.2 lb/10^6 Btu sulfur. When that was arrived at, I guess I was still in college, and I can't find in all the literature how it was derived. What is the basis? I have never seen a sample of scrubbers that it was based on.

PRINCIOTTA: It was based on direct measurements of the first two scrubbers that were installed here in the United States. The one that they cite usually in the literature is the Kansas Lawrence unit, I think Lawrence No. 4, which was a combustion engineering scrubber. It was achieving something like 75 percent removal at the time they measured it, which translated to a 1.2 lb $SO_2/10^6$ Btu. That is really the basis of it. So ordinarily, the air programs people have to identify a specific facility, or at least related facilities, that have achieved a level of control consistent with the standard that they have set. So it was based on that Lawrence Unit. They also made some measurements at the Uni Electric Merrimack Station, which were similar in nature.

COREY: In light of this, do you feel that that was an adequate sample? Or adequate representation of scrubber technology at the time?

PRINCIOTTA: Well, they only had two scrubbers in the whole country at the time and they measured both of them. This is almost a legalistic question about what is commercially demonstrated. Those particular units never really operated very well. I won't get myself involved in legalistic debate along those lines.

SOMEONE FROM THE DEPARTMENT OF ENVIRONMENTAL RESOURCES IN PENNSYLVANIA: Could somebody discuss or summarize the water requirements issue for preparation plants?

PRINCIOTTA: I am not sure that I can. I believe that (Jim may want to supplement me on this), or my understanding is that, our Effluent Guidelines Division is in the process of considering an effluent guideline on coal prep plants. Can you supplement that, Jim?

KILGROE: They have, I think, proposed standards which would apply to coal mining and auxiliary operations, such as coal preparation and waste disposal. It is my understanding that they are now in litigation with the National Coal Association and that they are going back and looking at the data they used to set the proposed standards. Probably in another year or so they will be modified. I don't know who is going to win the court battle, but I think really what the contention is, is whether or not you can have, say, a zero discharge on a coal preparation plant. That seems to be the major point. But there are standards, and I think they encompass pH, total iron, and maybe manganese, or one or two other elements.

UNGAR: I think that Bill Poundstone has some comments on that also.

POUNDSTONE: I suspect the question was more with reference to the amount of water needed, because of economics, than to regulations. Coal cleaning plants clarify and reuse the water that is in their circuit. And, while there are large volumes of water in the inventory, the amount of water that leaves the system consists of the water that goes out with the coal or the water that would be thermally dried and therefore can go into the atmosphere. In terms of gallons per minute, it may be of the order of 300 to 500 gallons a minute for a pretty fair size cleaning plant. It is not a major amount of water in comparison with coal utilization such as power generation or gasification.

UNIDENTIFIED PERSON FROM FLOOR: I believe that Mr. Princiotta said that the existing standards were directed at ambient health effects but that was not true of new source standards. If they are not directed at that, then I would just wonder, in this environmental energy area of ours, what need of society they are directed at solving?

PRINCIOTTA: That is a pretty difficult one, too. I am marginally qualified to respond to it and since I am the only one on the panel, I will give it a try. Basically, the concern, I think, by the Congress was of ever-increasing emissions of various pollutants, not just the sulfur oxides, from various sources. If you take a look at some of the trends, you will find that with even our present regulatory strategy, which includes NSPS and also controls on existing sources, total SO_2 emissions across the country are increasing, and will increase for the next 10 or 15 years.

You might say, "So what, if that doesn't affect ambient air qualities of sulfur dioxide?" Well, the so what is that there are a lot of other implications of emissions of these pollutants. There is a lot we don't know about pollution. The atmosphere is a very complex chemical reaction device and the input ingredients to a large extent are the criteria pollutants, and some of the other pollutants that we are studying now. Things of concern such as sulfates, acidic sulfates, which could conceivably be health effect problems, acid rain, haze, and other environmental impacts that may not be directly related to ambient SO_2 are, I think, of the concern of the Congress. That is why the emphasis on new source performance standards.

There is another reason, too. I will just give you a personal opinion. Look at all the complications of a strategy, an environmental control strategy, that ends up controlling sources to meet an ambient air quality. In order to do that right, you must have all kinds of health effects information. You have to have your monitoring down completely pat. You have got to have your transport and transformation chemistry down precisely. And, if any of your links are weak in that system, the whole chain is weak. There are several who theorize that we will never have all of those answers in our lifetimes. And if we are serious about cleaning up the environment, we perhaps need a little more straightforward approach that would involve just putting the best technology we can on new sources. And that will result in cleaning up the environment, in a less quantitative manner. So that is about the best I can do on that one.

UNGAR: I think that Bob Reeves may have a post script on that one.

REEVES: Well, as I understood, the act originally was to meet, achieve, and maintain the ambient air quality standards which had been established in '70, and therefore also require some constant emission control. And I thought that I heard, but I am not too sure that I did, again recognizing the technology was certainly a part of the development, that a constant emission control was to be set which was to achieve and maintain these ambient air quality standards. Now if that is not the case, I guess we are going to have to start all over someplace.

With respect to the ambient air quality, and I think Frank has brought up a question of large unknowns in terms of this transportation phenomenon, which we know essentially nothing about, there has been a lot of speculation as to the specifics of it. There is still a tremendous amount of work to be done. The fact remains, that if you look at the AQCRs across the United States, (Editor: a long, parenthetical digression is omitted at this point) the ambient air quality in this country is, as relates to SO_2, much better than originally thought of. The reason for that is that there have been a lot of us, including EPA and the state people, who got at the business of going out and just seeing what this air quality truly is. I think this, as I said earlier in my comments, has had the effect of allowing the existing unit concept or the existing units, in some of these states at least that we operate, to take another look at this thing and come up with revisions to their SIPs that reflect this concept. I think that is a very important move at least for an existing unit concept, which will at least help preserve the energy supply that we have without tearing it apart with some of these still existing source performance standards that we have in the states. But I am quite frankly a little confused. I have legal training myself and I have never interpreted that 1.2 was the result of what technology showed. I thought it was a combination of what technology showed and what was necessary to meet, achieve, and maintain the ambient air quality.

UNIDENTIFIED PERSON FROM FLOOR: The last report I read, I think said that SO_2 was down substantially over the last 5 years. Am I not correct?

PRINCIOTTA: I think that you are. If you look at the various AQCR's and the ambient levels of SO_2, you will find that there are fewer air quality control regions that are out of compliance than there were 5 years ago. On the other hand, I guess we should bring up (again, I am by no means an expert in this area) the concern that EPA now has, and many others have, for compounds other than sulfur dioxide that involve sulfur, mainly these acidic sulfates. The EPA is working very diligently on generating a data base that will allow us to ultimately come to some conclusions as to modification of our present SO_2 ambient air quality standard. I understand by 1979, they hope to come out with a new criteria document, which is basically the predecessor to a possible revised standard. I know that sulfates are being very actively considered and there is a chance that the next round of sulfur oxide standards might, in fact, aim at acidic sulfates. There is also a chance, and I can't give you probabilities on this, that we will find, based on what we know, that the sulfate problem may be more severe than the sulfur dioxide problem, and that SO_2 might really only be a crude proxy for what really is the health problem, namely these acidic ammonia and other acidic sulfates. If this is true, then much of the Northeast and even, for that matter, some of the Southeast have elevated sulfate levels, which could be troublesome and could call for increased sulfur oxide control. But, it is obviously too early to come to any conclusions until there is a revised ambient air quality standard and until the various strategies are developed to meet whatever that standard might turn out to be. My point is, that just because we are seemingly improving our sulfur dioxide situation insofar as the number of AQCRs that are out of compliance, doesn't necessarily mean that we have solved our sulfur problem.

STEVE FRIEDMAN, ERDA: A question for Mr. Pralle. There is an uncertainty in future regulations regarding the use of coal, in particular what we just heard about the possibility of tighter SO_2 regulating sulfates and I have also heard regulating fine particulates, tightening the NO_x standards and other things like that. How does that affect the availability of capital for coal burning installations?

PRALLE: Well, any uncertainty affects the availability of finance, because it involves a risk and banks do not like to take risks. I would say it affects particularly such projects, such financing mechanisms as project finance, where the sponsoring companies by themselves don't like to take on the additional obligations of guaranteeing the project but rather have the project stand on its own feet. In such projects, such project financing, the bank would be quite concerned if there were a question regarding the project's capability of repaying. In a case like that, where you might face a change in policy regarding the consumption of the output of the project, I would say you could only finance it if somebody took that risk other than the bank. In other words, if the utility would say, "Well, okay we will guarantee that this coal will be burned whether it is or not," or if the mining company comes along and says, "Okay, we guarantee that we can sell somewhere else if we can't sell here." It is an uncertainty and it is a risk factor and it affects financing and it certainly increases the cost of financing.

JOHN JOHNSON, SOUTHERN CALIFORNIA EDISON: I realize that all the emphasis of this conference has been on sulfur removal and SO_2 emissions, but in view of the projected tightening on NO_x emissions, I wonder if there are any research study results or test results, even though nitrogen—fuel nitrogen—might be a small contributor for NO_x emissions, to show whether coal cleaning has any potential for reducing fuel nitrogen contents?

GOUSE: If the coal nitrogen happens to be attached to ash material that is washable, then the coal cleaning would have an effect. But if we have coals where the nitrogen is bound more or less like an organic material, then it comes out even in a liquefaction process, and you really have to run it over a denitrification catalyst or something to get rid of it. I would say for some coals, it could be a major source of the oxides of nitrogen in the emissions rather than from the atmosphere. This can show up in atmospheric fluid-bed combustion where the combustion temperature is low enough that the atmospheric nitrogen probably doesn't contribute anything, but the coal bound nitrogen does. The same is true with shale oil, but it varies from day to day, even hour to hour, along the same seam.

KILGROE: I might say that we at EPA have done some speculations along that line and I think that probably Dr. Gouse is right, that most of the nitrogen is tied up with the organics in the coal. We believe that the traditional combustion modification will probably have a bigger effect upon the nitrogen oxide emissions than coal cleaning will itself. But we intend to do some experimental work to try to address that point.

I have another comment related to sulfur variability. We are very conscious of that as to how it is going to affect the use of coal cleaning as an emission control strategy. We are aware of the shortcomings of the data that the Bureau of Mines and EPA have developed on the cleanability and we are also aware the reserve information needs to be updated at the Bureau of Mines. We are now engaged in sort of an interagency program to increase our understanding and develop better information as to the variability of sulfur in coal and how you can really take it out, so that we are well aware of that problem. I guess this morning I spent some hours or 1 hour and 15 minutes in talking. I probably could have spent another hour talking about our current programs, which of course, we didn't have time to discuss.

HOWARD GOLAY, ILLINOIS DIVISION OF ENERGY: I would like to first address a question to Frank Princiotta. You said that coal gasification and coal liquefaction are losers for producing electricity. When you said that, did you mean all types of gasification, did you mean synthetic natural gas as well as low Btu gas, or how did you mean this?

PRINCIOTTA: I think that I threw in a couple of qualifiers, if I didn't I will repeat them again. I am referring to present generation technology, Lurgy for coal gasification, I won't even mention brand names for coal liquefaction processes presently under consideration, used with a standard steam boiler. Based on the economic studies that I have seen EPRI perform, that we perform within EPA, and ERDA in fact has performed, I think that I am just reflecting what these papers and reports are telling me. Those technologies are quite a bit more expensive than what is here today. Therefore, I don't see any incentive to move in that direction. However, I did point out that there is some potential with improved gasifiers, and with some very high-temperature gas turbines tied onto the steam turbines that we could turn around what looks like a major cost penalty. Perhaps you might want to address this to Dr. Gouse, he's probably closer to it. I am a student on the subject and he is more of a teacher.

GOLAY: Because we are involved like in the (unintelligible) project and this is why I brought the question up.

GOUSE: Well it depends more on what the standards are going to be than anything else. And, if we are going to have any standards, the best thing to do with coal is to burn it nice and simple and plain.

As you start cracking down on what you can let out if you go far enough there is only one solution, the chemically pure fuel, and we are headed on that track. Now maybe it is not 1985, but if you combine oxides of nitrogen, real tight sulfur, fine particulates, you may find a highly refined gas or liquid from a chemical conversion plant, where you can handle the emissions much more easily, may be a way out. With low Btu gas in today's dollars you could probably be pretty sure you could make it go for 250 to 275 a million Btu and you wouldn't have to do anything to the power plant, but that is still a high-priced fuel compared to what you can do today. Hopefully, it doesn't go up as fast as everything else does so that at some point it crosses, although that it not clear. Maybe the lines always stay parallel and never cross. So I don't know the answer. Today you wouldn't make gases or liquids from coal, you would go to scrubbers. But in 10 years—it depends not on technology but on regulation.

GOLAY: And this includes the combined cycle concept?

GOUSE: Well you wouldn't do anything very complicated at all if you had a choice. You only do those things when your back is against the wall.

UNIDENTIFIED PERSON FROM FLOOR: I think that they were saying that the 1.2 pounds was derived from a 70 percent efficiency. I guess that translates, say, to a coal whose variability never would exceed 2½ percent. I was wondering, is there a commercially approved FGD technology that would apply to the high-sulfur, high-chloride coals of the Illinois basin, for example, that could be used there if they can't import the Western coal?

PRINCIOTTA: To meet which standard?

UNIDENTIFIED PERSON FROM FLOOR: To meet, say, a revised new source standard.

PRINCIOTTA: Well, this is exactly what EPA is in the process of considering. There are a whole series of studies under way right now that EPA is sponsoring. Also, Research and Development is assisting in this effort and it is a very open question as to just what is the capability of flue-gas desulfurization to meet a more stringent standard. And I can say this, that there are scrubbers operating now that reportedly (and this is second hand information through our contract with talking to utility people) are achieving SO_2 removal efficiencies much higher than the present NSPS. I know from direct experience at our Shawnee lime and limestone test facility, which I have been intimately involved in for about 3 years, that we very easily achieve standards, the equivalent of standards, a factor of two more stringent than our present standards. But, it is a complicated question. And, you are right, coal variability is a variable and there is an increased cost associated with this tighter standard. Lime is more attractive for these higher SO_2 removal efficiencies cases than limestone and you could conceivably, if you set the standard too tight, knock out limestone as a possibility. You have the option of adding magnesium oxide or other magnesium compounds, as they do at Bruce Mansfield to get higher SO_2 removal efficiency. So, it is a complex situation that is under study right now.

UNIDENTIFIED PERSON FROM FLOOR: I have a question that is directed to Bill Gouse. What would the effect of the 0.6 standard be on the ERDA Programs?

GOUSE: Well 0.6 would cause you to use a scrubber with solvent refined coal because the best that comes out is about 0.8, and it is already stated that it's iffy on atmospheric fluid-bed combustion as to whether you could make it without a scrubber. This is the reason why we have in the program a variety of technologies, because we don't know what the ultimate emissions target is. In order to make sure that certain options are available, we are aiming at a variety of possible emission control levels, so that we do have something that we can actually do. The tighter the standard, generally, the more complex the system has to be to deal with it. Also it begins to move toward doing it right where you have all the coal in one place rather than where your ultimate use is. That is, putting at the mine mouth the preparation, liquefaction, or gasification plant and producing a finished clean product right there, rather than distributing the stuff all over the place and trying to handle it in a dispersed way. We are not in the standard setting business. We just have to observe the way that society seems to be going and try to make sure that the R&D program takes account of what is happening. It doesn't do any good at all to develop technologies that aren't going to be acceptable, and we try to avoid that.

JIM SHAY, SOUTHERN CALIFORNIA EDISON: I don't mean to try to keep Frank at work all the time, but I do have a question directed to you. Earlier, you mentioned that EPA or Congress is in the process of considering making some state SIPs less stringent. I would like to hear a little more from you, or maybe Dr. Gage would like to answer that question. The second part of it is, there is some speculation saying that EPA may apply the new source performance across the board, to the existing units too. Is that being considered? Those are my two questions.

PRINCIOTTA: I think that you heard as well as I did today what Senator Randolph mentioned, that they are considering modifications to the Clean Air Act, which would encourage the states to loosen up their existing standards. I might point out that the Clean Air Act basically calls for the states to impose a cleanup strategy that is at least good enough to meet ambient air quality standards, and it can be better than that of many states. Particularly those in the West, as I am sure you are aware, have very stringent standards. Well, EPA has had for quite awhile a so-called clean fuels policy, which basically involves trying to encourage some of the states to back off a little bit in their intensity of setting some of the state implementation regulations.

I don't have any tremendous insight into this, except to say that some of the regulatory types that I have talked with have indicated to me that there is a trend in this direction—that states are in effect even now backing off. I think that Mr. Reeves even mentioned that in his discussion. Maybe he can amplify on that a bit.

Let me just answer your second question. I am not personally aware of any move afoot to require, I guess basically, scrubbers on all existing sources. I doubt if that, to me, seems like a very imaginative extrapolation on this BACT deliberation that is going on right now. I don't think that is in the offing at all. Bob would you like to comment on the trend toward relaxing SIPs.

REEVES: I would like any opportunity I can on that Frank.

PRINCIOTTA: I think that is one of the few things that we agree on, so I'll pass the baton on.

REEVES: You're correct. I think that the Seek Act back in 1974 and, in fact, part of that Clean Fuels Policy, specifically told the EPA to take a look at these existing units strategies for existing plants. As I said earlier, I think that there are many places, at least in AEP, to look. We operate over a seven state area, and in everyone of those states there has been a significant look at and revisions. In some particular cases, this is still being worked on. But essentially, in most of these states that are coal producing, and very effective and very high coal producing Eastern states, they have realized and recognized that they need to utilize that existing fuel supply and have done a pretty good job. I must give credit to Frank and his organization with regard to region 5. They did a fairly decent job in terms of looking at the state of Ohio.

During the luncheon time I didn't want to interrupt the senator, but I happen to be a native of West Virginia although I work in Ohio, and I know what he is talking about when he talks about the smoke drifting across the Ohio River. But, I can assure you that with any good plan or strategy that will look at ambient air quality, be it in Ohio or the border states of West Virginia or Kentucky, and look at the real data and look at the configuration of the plant, there is no doubt in my mind that a proper emission control can be set. One which will achieve just what everybody is looking for in the ambient air quality with the existing coals in those areas. I suspect, pretty much, that an awful lot of states in the Eastern part of the country will be undertaking or have undertaken similar action. I think that it is essential to preserve any electrical energy that we have.

I would like to add another comment here. I think that one of the most difficult and maybe the most serious parts of this whole problem in terms of the energy supply is the uncertainty. I would hope that from a practical standpoint, we could stick with what we have got now, in terms of these new source performance standards. I don't like them. Very few people that I know do. But with these uncertainties, I for one don't know how anyone can generate any kind of strategy, and when I mean strategy I mean the necessary capital to develop this. I think our banking friend here made it quite clear that the risk situation in terms of getting at this problem does create a very serious, in my mind, financial problem. I would hope that there would be some reasonable rationale in terms of allowing us to proceed along a solid state, which would allow this technology to go. Because certainly, companies are not going to invest multimillion capital dollars in a system that they have no assurance will at least be given an opportunity to recover that capital.

UNGAR: I would like to thank our panelists, they have provided us with a very interesting, provocative discussion. I would like to turn the meeting over to Steve Gage who is going to give us our concluding remarks.

GAGE: First of all, I think that we should feel very good. This is one of the few meetings that I have ever attended, particularly with such a broad spectrum of opinion, where everything is run on time. So we are going to be concluding here very close to time and I am not going to prolong that. I do want to thank you very much as participants in the meeting. I think you have given us a great deal. I appreciate your candor, your forthrightness, and your very enthusiastic participation. I would like to thank Ed and the rest of the people from Battelle for cosponsoring this meeting and providing such excellent cooperation in getting this meeting going in such a short period of time. We felt the timing was critical and it was only with Battelle's help that we could pull this off. I want to thank my staff for their participation and particularly Bill McCarthy who handled so many of the logistics on getting the conference together and getting it going.

Did we meet our objectives, or not? Well I think that our primary objective in this meeting was an educational one. Most of the meetings that EPA holds, at least on the R&D end, we think of as being information transfer or technology transfer meetings. That is a two-way street. And I guess that from that point of view, we did meet our objectives and I think that we learned a lot from you. That was what the meeting was all about.

I hope on the basis of proceedings that will develop from this meeting that we will have the beginning of a good data base, and an identification of most, if not all, of the substantial issues that we are going to have to deal with in carrying out this study of the role of the Federal government in coal cleaning. I think that many of the nontechnological barriers have been identified in this meeting and I think that you have given us a great deal of help in using this type of informal meeting in getting a headstart on what is going to be a tough study. I think that the results on this will inform ERDA, will inform the new Department of Energy, will inform EPA as to what the real issues are.

It has been tough to carry out this dialogue that we have been attempting the last 2 days amidst so much flux. The President's energy proposal is obviously going to be modified in many different ways up on The Hill. It is not altogether clear what all of the provisions of the proposal really mean, even within the administration circles. The question of the conversion of coal, particularly in the industrial, to a lesser degree in the utility, sector, is going to take many shapes and forms before it is finally put into the law. The question of tightening new source performance standards and the question of BACT under the new Clean Air Act amendments of course add a great deal to the complexity and confusion of our discussion. I really do think that in the back of our minds we have to hold some margins of error, some safety factor to take into account what we may have to do because of the potential health threat of interregional transport and interregional transport of the sulfates.

The problem is that we can't wait until all of the issues are crystallized and that is why we went ahead as quickly as we could with this meeting. And we, I think you found out, have reasonably thick skin. We hope that we haven't been desensitized, but frankly getting a little bit of humility spread on once in awhile probably does any government organization a great deal of good. We may have had a couple of extra doses from time to time during the meeting, but I think that we have learned a lot of very useful things from the session. We heal up pretty quickly.

I hope that we can count on you over the next few months. We are going to use our attendance lists for the conference essentially as a Who's Who in coal cleaning, adding additional names as you pass those names onto us. We hope to have a great deal of correspondence and dialogue with you. Thank you very much for participating and I hope to see you again soon.

Panel members (left to right): Frank Princiotta, Kurt Pralle, William Gouse, Edward Ungar, Robert Reeves, and William Poundstone.